COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

BOSTON GAS COMPANY d/b/a KEYSPAN ENERGY DELIVERY NEW ENGLAND	)	**D.T.E. 03-40**

INITIAL BRIEF OF THE ATTORNEY GENERAL

Respectfully submitted,

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I. INTRODUCTION

Pursuant to the briefing schedule established by the Department of Telecommunications and Energy ("Department") in this proceeding, the Attorney General submits his Initial Brief responding to the Petition of Boston Gas Company d/b/a KeySpan Energy Delivery New England ("Boston Gas" or "Company") for approximately a $61.3 million, or 9.59 %, increase in gas distribution rates (the "Petition" or "Filing") under G. L. c 164, §§ 1E and 94. In addition, Boston Gas requests approval of a price cap performance-based regulation ("PBR") plan under which the Company proposes to adjust its rates annually for five years or more.

As is customary in a rate proceeding, the Attorney General will provide his final recommendations concerning the Company's revenue requirements in schedules attached to his Reply Brief.

II. OVERVIEW

Boston Gas petitioned the Department for approval of a $61 million increase in its base rate charges for gas distribution service. This proposed rate increase is one of the largest increases in distribution rates ever requested by a Massachusetts gas utility. If approved, the Company will be able to increase its distribution rates by more than 20 percent, independent of any increases in natural gas costs recovered through the Cost of Gas Adjustment ("CGA"), which the Company has forecast for November 1, 2003 at $0.93/therm. The November 1, 2003 CGA is estimated to be approximately 50% higher than at the start of last year's heating season. When the proposed distribution increases are combined with forecast CGA increases, the average R-3 residential heating customer would suffer a 40% bill increase.

The high cost of energy is one of the critical economic issues confronting the citizens of the Commonwealth. Massachusetts' families and businesses are facing some of the highest costs for natural gas services in the country. Families are still struggling to pay unusually high heating bills from last winter and in this case are faced with the potential of ten years of additional annual distribution rates increases. Given the current economic climate, Boston Gas customers should not be compelled to shoulder additional financial burdens.

In its last base rate case, *Boston Gas Company*, D.P.U. 96-50, the Department approved a five-year performance based rate ("PBR") plan for the Company. A performance based rate plan allows a company rate flexibility with less regulatory oversight. A company operating under a PBR plan, however, is required to maintain its quality of service. For each of the five years following the Department's decision in D.P.U. 96-50, the Company received annual increases in rates to offset the effects of inflation and allow it to operate the distribution system in an efficient manner. For several years after the PBR began, the Company failed to prevent the deterioration and degradation of its distribution system. For example, the Company failed to prevent leaks which caused inadequate system pressure in over 1,500 streets and which required the Company to spend tens of millions of dollars in repair costs. The Company also failed to replace its meters every seven years, as required by statute. As a result of this failure to maintain the system, the Company spent hundreds of millions of dollars in capital additions by the end of the test year to bring the distribution system back up to standard. The Company has taken advantage of rate case/PBR timing by initially deferring maintenance and then loading the test year with inflated capital additions and high levels of expenditures.[1] Any costs incurred to rehabilitate the distribution system should be borne by the Company and its shareholders, not by customers who suffered from the prior lack of routine maintenance and plant replacement.

The Company has also avoided Department review of its actions. KeySpan has never sought Department review of its acquisition of Eastern Enterprises to determine whether the acquisition would harm customers.[2] KeySpan's acquisition of Eastern Enterprises has resulted in increased costs, not savings. The Company is seeking to charge Boston Gas customers costs that are the responsibility of the Essex and Colonial Gas subsidiaries. This request should be denied, so the Boston Gas customers are not harmed from the acquisition by KeySpan. In addition, the Company has attempted to evade statutory requirements for Department review of affiliate and third party contracts of more than one year by only entering into renewable one year contracts for services that it intends to acquire for many years in the future. Without Department review or

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[1] For several years preceding the acquisition by KeySpan, the Company earned at or above its allowed return on common equity. The Company had the ability to attract capital on reasonable terms for system additions.

[2] In previous Department merger approvals, rate freezes, not ten years of annual rate increases, were approved.

approval, KeySpan (1) established and contracted with a service company to provide a majority of the Company's customer and regulatory accountability functions, including billing, records, customer services, accounting, and finance activities with total annual billings of $90 million; (2) relinquished control and management of the Company's $300 million gas portfolio, the cost of which is recovered dollar-for-dollar through the Cost of Gas Adjustment Clause ("CGAC"); (3) charged the Company for $650 million in new debt, which cost the Company over $45 million and simultaneously raised the Company's real debt ratio to over 60 percent and (4) recorded costs on the Company's books of account contrary to the Department's rules as contained in the DTE's Uniform System of Accounts for Gas Companies. As a result, the Company ceded control of over 70 percent of its costs without Department approval, employing various tactics to circumvent the spirit of the law. The Department should reject such practices in its order.

While the Company was failing to provide needed plant replacement to its system, and circumventing statutory review requirements, KeySpan was paying its management and officers exceptionally generous pay and benefits, including expensive automobile allowances and extravagant travel and entertainment. KeySpan now seeks to charge part of those costs to the Company's customers, many of whom, as the Department understands from the public hearings early in this proceeding, are struggling to pay their ever-increasing heating bills.

The Company's poor operating performance and actions that evaded Department review justify the Department's heightened scrutiny of the Company's proposed increases in costs. The various individual adjustments to the Company's revenues and costs recommended below provide the Department with more than sufficient basis to deny Boston Gas its requested initial increase in rates. The Department also should deny the Company's PBR plan.

III. PROCEDURAL HISTORY

On April 16, 2003, Boston Gas filed with the Department a PBR Plan including tariff schedules of proposed rates and charges designed to increase the Company's annual revenues by approximately $61.3 million, or 9.59 percent, based on a test year ending December 31, 2002. The Department suspended the effective date of the requested rate increase until November 1, 2003, and opened an investigation into the Company's proposal. Notice of Public Hearing, April 24, 2003. On April 16, 2003, the Attorney General intervened as of right pursuant to G.L. c. 12, §11E, and commenced filing discovery by agreement with the Company. On May 19, May 20, May 21 and May 22, 2003, the Department conducted public hearings at the Department, Acton Town Hall, North Shore Community College, Lynn and Quincy City Hall, respectively. On May 23, 2003, the Department convened a procedural conference to establish a schedule for discovery, hearings and briefs. At this conference, the Department allowed the Bay State Gas Company ("Bay State"), the Berkshire Gas Company ("Berkshire"), the Massachusetts Department of Energy Resources ("DOER"), Massachusetts Community Action Program Directors Association, Inc. ("MASSCAP"), Massachusetts Oilheat Council, Inc. ("MOC"), Massachusetts Alliance for Fair Competition, Inc. ("Alliance"), Associated Industries of Massachusetts ("AIM"), Massachusetts Development Finance Agency and the United Steelworkers of America AFL-CIO-CLC to intervene as full participants. The Department also allowed Boston Edison Company, Cambridge Electric Light Company, Commonwealth Electric Company together d/b/a NSTAR Electric and NSTAR Gas Company (collectively, the "NSTAR Companies"), Fitchburg Gas and Electric Light Company ("FG&E") and Western Massachusetts

Electric Company ("WMECo") to intervene as limited participants.

On June 6, 2003, the Attorney General filed a Notice of Intent to File Testimony of two witnesses: Lee Smith of La Capra Associates on PBR and/or rate design issues and David Effron of the Berkshire Consulting Group on revenue requirement issues. Also on June 6, 2003, MASSCAP file a Notice of Intent to File Testimony of Elliott Jacobson, Energy Director of Action, Inc. and chairman of the New England Community Action Association Energy Committee, on the burdens of low income families and existing policies and programs that assist low income customers.

At the second procedural conference on June 23, 2003, the Department allowed The Energy Consortium and New England Gas Company to intervene as limited participants.

The Department conducted twenty-six days of evidentiary hearings commencing on June 26, 2003, and continuing until August 11, 2003. During the twenty-six days of evidentiary hearings, Boston Gas presented numerous witnesses, each of whom offered testimony on a variety of topics with a certain degree of overlap: Patrick J. McClellan, Director of Rate Recovery for the Company, on cost of service; A. Leo Silvestrini, Director of Rates and Regulatory Affairs for the Company, on marginal cost and rate design; Ann E. Leary, Manager of Rates for the Company, on cost allocations and revenue adjustments; Ronald B. Edelstein, an outside consultant, on research and development funding; Dr. Lawrence R. Kaufmann, an outside consultant, on PBR issues; Joseph F. Bodanza, Senior Vice President of Regulatory Affairs and Chief Accounting Officer for the Company, on PBR and other issues; Paul Moul, an outside consultant, on the cost of equity and the proposed pension reconciliation mechanism; and Justin C. Orlando, Vice President of Human Resources for the Company, on issues relating to employee salaries, benefit plans and incentive compensation.

On July 7, 2003, the Attorney General submitted prefiled testimony of his two witnesses, Lee Smith and David Effron. Also on July 7, 2003, MASSCAP submitted prefiled testimony of its witness, Elliott Jacobson. On August 4, 2003, the Company submitted rebuttal testimony of Mr. Moul, regarding Mr. Effron's testimony on the impact of the Company's proposed pension reconciliation mechanism on the cost of equity; Mr. McClellan, regarding Mr. Effron's testimony on the Company's incremental cost adjustment and income tax allocation; and Dr. Kaufmann, regarding Ms. Smith's criticisms of his TFP and econometric research. The Attorney General filed surrebuttal testimony of Timothy Newhard to address Mr. Moul's rebuttal testimony. The Attorney General was also granted the opportunity on August 11, 2003, the final hearing day, to submit oral surrebuttal testimony by Ms. Smith regarding the rebuttal testimony of Dr. Kaufmann.

IV. STANDARD OF REVIEW

In reviewing the "propriety" of rate increase proposals by a utility company under G. L. c. 164, § 94, the Department must determine whether the proposed rates are just and reasonable. *Attorney General v. Department of Telecommunications and Energy*, 438 Mass 256, 264 n. 13 (2002); *Berkshire* Gas Company, D.P.U. 96-67, p. 6 (1996). Since incentive regulation acts as an alternative to traditional cost of service regulation, the "just and reasonable" standard of §94 also applies to performance-based ratemaking plans. *Boston Gas Company*, D.P.U. 96-50, p. 242 (1996) (Phase I); *Investigation by the Department of Public Utilities on Its Own Motion Into the Theory and Implementation of Incentive Regulation for Electric and Gas Companies Under Its*

Jurisdiction [hereinafter cited as *Incentive Regulation*], D.P.U. 94-158, p. 52 (1995).

Furthermore, for incentive plans the Department has stated:

> As a general proposition, a petitioner seeking approval of an incentive proposal shall be required to demonstrate that its approach is more likely than current regulation to advance the Department's traditional goals of safe and reliable energy service and to promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation.

Incentive Regulation, D.P.U. 94-158, p. 57 (1995). "The burden of proving the propriety of a rate increase remains with the utility seeking the increase." *Town of Hingham v. Department of Telecommunications and Energy*, 433 Mass. 198, 213-14 (2001) citing *Metropolitan District Commission v. Department of Public Utilities*, 352 Mass. 18, 24 (1967); *Wannacomet Water Co. v. Department of Public Utilities*, 346 Mass. 453, 463 (1963). The Company bears the burden of proving each and every element of its case by a preponderance of "such evidence as a reasonable mind might accept as adequate to support a conclusion." G. L. c. 30A, §1(6); *Fitchburg Gas and Electric Light Company*, D.T.E. 99-118, p. 7, n.5 (2001). If the Company fails to carry this burden, the Department must deny the Company's requested rate treatment for the proposed adjustment. *Fitchburg Gas & Electric Light Company. v. Department of Public Utilities*, 375 Mass. 571, 582-583 (1978).

V. ARGUMENT

A. THE DEPARTMENT SHOULD EVALUATE THE KEYSPAN MERGER UNDER THE PUBLIC INTEREST STANDARD AND DISALLOW COSTS UNDER §94 THAT KEYSPAN UNFAIRLY ALLOCATED TO BOSTON GAS.

1. THE DEPARTMENT SHOULD EXCLUDE KEYSPAN'S ALLOCATION TO BOSTON GAS OF AFFILIATES' NON-INCREMENTAL COSTS.

In this proceeding the Company claims not to seek recovery of direct costs from the KeySpan merger, but does want Department approval of some very important cost impacts of this merger without a showing of "no net harm" to any of the customers of the former Eastern Enterprises companies.[3] The Company did not seek any Department review of the proposed merger or the actual merger itself in conjunction the proposed PBR rate plan. This proceeding, however, presents the first time that Boston Gas customers face the prospect of paying the non-incremental costs associated with the *Essex* and *Colonial* mergers. *Eastern / Essex Merger*, D.T.E. 98-27, pp. 45-48 (1998); *Eastern / Essex Merger*, D.T.E. 98-27-A, pp. 4-5 (1998); *Eastern / Colonial Merger*, D.T.E. 98-128, pp. 88-89 (1998). The Department evaluates mergers under the public interest standard of review to determine whether the merger will do "no net harm" to rate payers. *Attorney General v Department Telecommunications & Energy*, 438 Mass.

[3] Nothing in the Department's order, *Mergers And Acquisitions*, D.P.U. 93-167-A (1995), would prevent the Company filing for an examination of the KeySpan merger in conjunction with the proposed rate plan. *Attorney General v Department Telecommunications & Energy*, 438 Mass. at 268-269 (standards of §96 applied by analogy to portion of rate plan related to merger). The circumstances of this case highlight the necessity for such an examination where the Company seeks a material change to the merger cost recovery method that the Department ordered for two other mergers it previously analyzed and approved under the "no net harm" standard. Good utility practice would provide the Department an opportunity to determine whether the customers of Boston Gas would be harmed by the KeySpan merger. *See* G. L. c. 164, §96.

256, 268-269 (2002) (upholding Department's application of the standards of G. L. c. 164, § 96, by analogy to examine holding company merger in context of merger-related rate plan filed under G. L. c. 164, §94). The Department analyzes the costs and savings associated with the merger to see if consumers would be no worse off with the merger than without it. *Boston Edison*, D.P.U. 850, pp. 7-8 (1983). Here, the Company did not present the type of detailed merger cost calculations or savings projections that the Department requires in the context of a merger related rate plan evaluation. *Investigation by the Department on its own motion, pursuant to G.L. c. 164, §76 and §96, for the Purpose of Establishing Guidelines and Standards for Acquisitions and Mergers of Utilities and Evaluating Proposals Regarding the Recovery of Costs for Such Activities* [hereinafter cited as *Mergers and Acquisitions*], D.P.U. 93-167-A, pp. 7-9 (1994). The Department should conclude from this lack of proof that merger costs and acquisition premiums exceeded merger benefits and that the Boston Gas customers are worse off with KeySpan than under Eastern Enterprises.

Since the Company could not quantify savings to Boston Gas that were passed on to its customers as a result of the KeySpan merger, Tr. 22, pp. 2986, 2990-2991, the Company logically could not seek the recovery of acquisition related costs. The Company apparently does not request recovery of these direct costs, but does seek approval of substantial regulatory changes caused by the KeySpan merger without a showing of "no net harm" to any of the customers of the former Eastern Enterprises companies. Boston Gas seeks to replace the incremental method of cost accounting approved by the Department in D.T.E. 98-27 and 98-128 for the recovery of Essex and Colonial merger related costs with a new accounting model based on cost assignments and allocations from KeySpan Service Company ("Service Company") under an SEC formula. *Compare Eastern / Essex Merger*, D.T.E. 98-27, pp. 45-48, *Eastern / Essex Merger*, D.T.E. 98-27-A, pp. 4-5 and *Eastern / Colonial Merger*, D.T.E. 98-128, pp. 88-89 *with* KEDNE/PJM-1, pp. 20-21. This proposal represents a fundamental alteration to those earlier merger decisions. The Department has approved a method for the recovery of merger related costs for the Essex and Colonial mergers under the "no net harm" standard for each of those mergers. *Eastern / Essex Merger*, D.T.E. 98-27, p. 69; *Eastern / Colonial Merger*, D.T.E. 98-128, pp. 104-105.[4] The Department has not previously approved the Company's new system of cost recovery imposed after the KeySpan merger for the recovery of those same costs, and the Company provides no convincing argument in favor of approval now.

In the *Essex* and *Colonial* cases, the Department had determined that those utilities could retain the synergies of the mergers for the period of ten year rate freezes as a method of merger cost and acquisition premium recovery. *Eastern / Essex Merger*, D.T.E. 98-27, p. 69; *Eastern / Colonial Merger*, D.T.E. 98-128, pp. 90-96. The Department decided that Essex and Colonial would only pay the incremental costs, and that Boston Gas should be responsible for the non-incremental costs, since Boston Gas would incur these costs anyway. *See Eastern / Essex Merger*, D.T.E. 98-27, pp. 45-48, *Eastern / Essex Merger*, D.T.E. 98-27-A, pp. 4-5 and *Eastern / Colonial Merger*, D.T.E. 98-128, pp. 88-89. Thus, the Department intended that Essex and Colonial customers would suffer "no net harm" under this analysis. The impact of this

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[4] The Attorney General has appealed the merger decision in *Eastern Enterprises-Colonial Gas Company*, D.T.E. 98-128 (1999) and frames his arguments, as he must, in this case with the understanding that Department orders are enforceable until modified or overturned by the Massachusetts Supreme Judicial Court. As the appeal is still pending, nothing in this brief should be construed as an adverse admission or waiver of any legal or factual argument that the Attorney General may make in the pending appeal.

arrangement on the customers of Boston Gas has not been before the Department until this case.

The KeySpan merger upsets the balance between ratepayers and shareholders for the Essex and Colonial mergers. The creation of a Service Company, with the majority of costs residing at the Service Company level and then distributed to Boston Gas, Colonial Gas and Essex Gas under SEC formulas, completely undermines the basis for the Department's merger orders in D.T.E. 98-27 and 98-128. Circumstances have materially changed. Boston, Essex and Colonial Gas are now just one of the many regulated and non-regulated companies that comprise a vast KeySpan enterprise. Prior to the KeySpan merger, Boston Gas incurred and retained the non-incremental costs of services provided to Essex and Colonial. Now, a fourth party, the Service Company, incurs these costs. SEC formulas do not allocate Service Company costs based on the concept of incrementality. There are no longer costs emanating from Boston Gas, a utility performing the same services that Colonial Gas and Essex Gas perform. There is another entity that serves its client companies and incurs costs for the benefit of these numerous and diverse businesses. The definition of non-incremental now differs greatly from what the Department originally envisioned. Boston Gas has not demonstrated that this new system of cost accounting maintains the status quo for Essex and Colonial customers, or that Boston Gas customers do not suffer a harm.[5] As a result, the Department should reject all Essex and Colonial

[5] For the first time in any proceeding, the Company proposes that Boston Gas customers pay the non-incremental costs associated with the Essex and Colonial mergers. While the Department may approve a merger under the "no net harm" standard of G. L. c. 164, §96, a request for a general rate increase triggers the "just and reasonable" standard of review in G. L. c. 164, §94. *Attorney General v Department Telecommunications & Energy*, 438 Mass. at 268-270; *Cambridge Electric Light Company v. Department Public Utilities*, 333 Mass. 536, 358-538 (1956) (performance of "public interest" analysis does not discharge the duty to test the propriety of rates). When deciding whether to allow the recovery of Essex and Colonial merger related costs embedded in the non-incremental costs proposed to be charged to the customers of Boston Gas, the Department must not use this rate setting process to validate the acquisition premium from the Essex and Colonial cases. *Duquesne Light Co. v. Barasch*, 488 U.S.

Gas costs included in the Company's proposed cost of service[6].

In the alternative, if the Department concludes that the Company should be charged some level of non-incremental costs from Colonial and Essex, the Company has still not established that the method it used to distinguish incremental from non-incremental expenses results in a proper allocation of expenses among the three companies. The Company claims that the Department, in approving the acquisitions of Essex and Colonial, specified that only incremental costs incurred by Boston Gas in serving Essex and Colonial would be assigned to those two companies for Boston Gas ratemaking purposes. Exhibit KEDNE/PJM-1, at pp. 20-21. The Boston Gas books of account already reflect the allocation of expenses to Essex Gas on what Boston Gas deems to be an incremental basis.[7] However, with regard to Colonial, the Boston Gas books of account reflect an assignment of costs provided through the Service Company, including the allocation of non-incremental costs. The Company proposed an "Incremental Cost Adjustment" to the test year cost of service that allegedly charges Colonial only for incremental costs incurred by Boston Gas in serving Colonial and reallocates all costs deemed to be non-incremental back to Boston Gas. The Incremental Cost Adjustment increases pro forma test year expenses by $7,256,000, to adjust for costs that were allocated to Colonial on the actual books of

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299, 309 n. 5 (1989) (capital assets should not "be valued by the stream of income they produce because setting of that stream of income was the very object of the rate proceeding"); *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 601-607 (1944) (upholding the rejection of the use of "fair value" rule and any investor right to appreciation in the value of utility property).

[6] Since the Company has not used a representative test year, all Service Company costs should be excluded from the Company's cost of service, as explained *infra*.

[7] The Company does make an adjustment to remove $425,000 of "non-incremental" costs that were not allocated to Essex by the Service Company. Exh. KDNE/PJM-2 (revised), p. 26. The adjustment was based on allocating the same types of Service Company costs that were allocated to Colonial. Exh. AG-1-11.

account, but were deemed by the Company to be non-incremental costs and charged back to Boston Gas.

Exh. AG-11-1 describes how the Company determined which costs were incremental. The Company established three categories of costs:

1. Costs associated directly with a project activity directly assigned to Essex or Colonial. Such costs are incremental and not allocated to Boston Gas for ratemaking purposes.

2. Costs that are related to activities such as field marketing, leak surveys, and meter operations. Such costs were deemed to be incremental and not allocated to Boston Gas for ratemaking purposes.

3. Administrative and general expenses including finance, human resources, legal and corporate management. To the extent such costs were not directly assignable, they were deemed to be non-incremental and allocated to Boston Gas for ratemaking purposes.

As explained by Mr. Effron, the Company's method of categorizing expenses as non-incremental is improper, in that certain incremental costs are deemed to be non-incremental:

> For example, the costs of the tax staff, which had been allocated in part to Colonial on the actual books of account, were re-allocated in their entirety to Boston Gas as part of the Incremental Cost Adjustment. While it is reasonable to expect that there would be economies of scale from integrating the tax staff functions of Boston Gas and Colonial, there would most likely still be some incremental tax staff costs attributable to Colonial. Similarly, activities such as internal audit and purchasing management were re-allocated in their entirety to Boston Gas for ratemaking purposes. Again, while it reasonable to expect that there would be some economies of scale in these areas, there would still likely be some expenses that are properly attributable to Colonial.

Exh. AG-42, p. 6.

Mr. Effron then presented an analysis of the Company's administrative and general ("A&G") expense, comparing the level of expense from the years 1996-1998, prior to the acquisition of Essex and Colonial, to the level of expense in 2002, after the acquisitions. Based on this analysis, Mr. Effron concluded that, even after allowing for inflation and system growth, the A&G expense incurred by the Company increased from the 1996-1998 period to 2002. This would imply that there were no economies of scale or efficiencies from the Essex or Colonial mergers and that all costs allocable to Essex Gas and Colonial Gas are, in effect, incremental costs. He made two recommendations based on this conclusion:

> First, unless the Company can demonstrate that the increase in A&G expenses since the period from before the merger is due to factors other than the way expenses are allocated among the affiliates, the Incremental Cost Adjustment should be reversed. The A&G allocated to Boston Gas even before the Incremental Cost Adjustment is already higher than it should it be based on the escalated level of A&G incurred by Boston Gas before the merger. To the extent that the Incremental Cost Adjustment increases the pro forma A&G expense included in the cost of service, it only serves to exacerbate this discrepancy.
>
> Second, the A&G expense allocated to Essex should be increased, as the Company uses substantially the same method to determine the incremental expense attributable to Essex that it does for Colonial.

Exh. AG-42, pp. 12.

Company Witness McClellan responded that Mr. Effron's analysis failed to consider unexpected accounting changes that had taken place between the 1996-1998 time period and 2002 occasioned by the KeySpan merger and the switch to Service Company formulas. Exh. KEDNE/PJM-14, pp. 3-4. Mr. McClellan claims that when the effect of those accounting changes are considered, a proper comparison of the relevant expense accounts shows a decrease in expenses from the 1996-1998 time period to 2002, thus establishing that the Company had achieved economies of scale that it should be allowed to retain. *Id.*

There are a number of problems in the Company's expense comparison. Most importantly, it does nothing to address the primary problem with the Company's method of determining non-incremental costs: it deems costs that are in reality incremental to be non-incremental. The expense comparison presented by Mr. McClellan also does not establish that any efficiencies have been achieved as a result of the Essex and Colonial mergers. Mr. McClellan's comparison establishes only that an accountant can carefully include or exclude expenses from such a comparison and prove virtually anything.

Mr. McClellan limited the expenses included in his comparison to expenses charged to certain accounts. Exh. KEDNE/PJM-14, Schedule 1. Virtually all expenses fluctuate from year to year. By selecting only certain expenses and by defining the expenses to be included, it is easy to show a "decrease" in expenses from one period to another. The Company claims that changes in accounting from 1998 to 2002 (changes in the Company's assignment of O&M expenses to Department accounts) distorted the comparison of selected O&M expenses from 1998 to 2002. This criticism applies to Mr. McClellan's comparison as well as Mr. Effron's. The accounting changes that distort Mr. Effron's expense comparison also distort Mr. McClellan's comparison of certain selected expenses. If Mr. Effron's comparison is to be expanded beyond A&G expenses, one should more broadly compare all O&M expense (with necessary adjustments), not just the expenses Mr. McClellan selected. Expanding the comparison to all O&M expenses neutralizes any effect that accounting changes have on costs charged to individual O&M expense accounts.

Mr. McClellan was presented with a comparison of average non-gas O&M expense excluding pensions and benefits and uncollectible accounts for the years 1996-1998 to the same expenses in 2002. Tr. 25. pp. 3527-3530. Mr. McClellan disagreed with the amount of uncollectible accounts expense eliminated in 2002. Tr. 25, p. 3532. Even after making the modification to uncollectible accounts advocated by Mr. McClellan,[8] however, the actual O&M expense incurred in 2002 was greater than the average expense incurred in 1996-1998 adjusted for inflation and system growth. *Id*., p. 36. The Department should conclude from this comparison that the Company did not achieve any measurable efficiencies or economies of scale as a result of the Colonial and Essex mergers.

In fact, Mr. McClellan prepared a similar comprehensive comparison of O&M expense but opted not to present it, relying instead on his comparison of selected accounts. RR-AG-101. The Company's study shows that the total non-gas O&M increased by 19% from 1996-1998 to 2002, greater than the 15.9% combined inflation and growth rate cited by Mr. Effron. *Id*., p. 2. This increase is prior to the assignment of the non-incremental costs to Boston Gas proposed by the Company. The Company's study also shows that non-gas O&M other than pensions grew from 1996-1998 to 2002 by 16% in this five-year time frame, approximately equal to the combined inflation and system growth rate. *Id*., p. 2. (Again, this comparison does not include any assignment of the proposed non-incremental costs to Boston Gas.) This growth of expenses further confirms the absence of any cost savings as a result of the acquisition of Essex and Colonial.

Only when the study selectively eliminates certain expense accounts does it show growth less than the combined inflation and system growth rate. The study eliminates sales expenses on the premise that "these expenses are covered by system growth, which Mr. Effron has not addressed in his analysis." *Id*., p. 3. Mr. Effron did, in fact, address system growth in his

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[8] This modification appears unnecessary. The uncollectible accounts expense eliminated in 2002 should be the actual expense booked in that year in Report to the Department, not the pro forma elimination of uncollectible accounts expense in the Company's cost of service presentation.

analysis. His 3.0% per year escalation factor (15.9% over five years) is a reasonable allowance for "inflation plus real system growth." Exh. AG-42, p. 10, 11. 3-8. The 3% annual escalation rate for the period from 1996-1998 to 2002 is well in excess of any measure of inflation during this period[9] and must necessarily include an allowance for real system growth, as well as inflation, contrary to the Company's characterization.

By selecting expenses that have increased the most from 1996-1998 to 2002 to eliminate from the study, it is easy to lower the escalation rate below a reasonable allowance for inflation plus real system growth. RR-AG-101, pp. 3-4. Given the Company's selective elimination of expenses, the Department should assign no weight to its comparisons. Even if the Company could hypothetically demonstrate that the Essex and Colonial acquisitions did result in economies of scale, this would not cure the basic defect in its development of the incremental cost adjustment: the Company's method of calculating the incremental cost adjustment assigns incremental costs, as well as non-incremental costs, to Boston Gas. As described above, to the extent administrative and general expenses such as finance, human resources, legal, and corporate management costs were not directly assignable, they were deemed to be non-incremental and allocated to Boston Gas for ratemaking purposes. "Non-incremental" is ***not*** synonymous with "not directly assignable." Finance, human resources, legal, purchasing, and property management costs are likely to be greater as a result of the integration of Essex Gas and Colonial Gas operations, although the amount of increased expense is not directly assigned or

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[9] If anything, the 3% escalation rate is highly conservative. For example, based on the standards established in the PBR approved by the Department in D.P.U. 96-50, an appropriate escalation factor would reflect the growth in Gross Domestic Product Price Index with an offset for productivity. Application of this standard would yield an average annual escalation factor significantly less than 3%.

allocated to these companies. There would be incremental expenses as a result of the existence of Essex Gas and Colonial Gas even though it might difficult to determine the precise amount of such incremental expense.

Mr. Effron clearly explained in his testimony that the definition of non-incremental costs used by the Company was too broad and resulted in an over-allocation of expenses to Boston Gas Company. The Company presented nothing to refute this testimony. The Company has not established that its method of distinguishing incremental from non-incremental expenses is appropriate and results in a proper allocation of expenses among Boston, Essex, and Colonial Gas pursuant to the Department's orders in the *Essex* and *Colonial* merger cases. Therefore, the Department should reduce the Colonial Gas A&G allocated to Boston Gas by means of the incremental cost adjustment by $6,880,000 and reverse the Essex Gas A&G expenses deemed by the Company to be non-incremental, $1,816,000, and included in the Boston Gas O&M expense. These adjustments result in a reduction of $8,696,000 to pro forma test year operation and maintenance expense included in the Company's revenue requirement.

2. THE TEST YEAR IS UNREPRESENTATIVE, AS SHOWN BY THE SEC AUDIT OF KEYSPAN SERVICE COMPANY.

Section 94 of Chapter 164 mandates that the Department set just and reasonable rates. The Company must provide sufficient evidence to support a finding that the Company's revenue requirement, including allocated Service Company costs, meet this test. *Fitchburg Gas and Electric Light Company*, D.T.E. 98-51, p.29 (1998) (the Department determines if SEC approved charges are appropriately included in rates for Massachusetts gas retail customers).[10] The Company bears the burden of proof on this issue. *Id*. If the Company does not meet its burden, then these costs must be excluded. *Id*. The Company also must prove that the costs it seeks to recover are representative of the level of costs that it will incur during the period that the rates will be in effect. *Fitchburg Gas and Electric Light Company*, D.T.E. 98-51, p. 39 *citing Western Massachusetts Electric Company*, D.P.U. 86-280-A, p. 49 (1987).[11] As explained in detail below, the Service Company costs are not representative. Because of the magnitude of these costs, the Department must reject the Company's request for rates based on them.[12] If the

[10] The Department has found that "[t]he SEC's allocation process makes no determination as to reasonableness or appropriateness under the standards that would be applied by the utility commission in the states in which the holding company's retail subsidiaries are located. Those functions remain with state commissions." *Fitchburg Gas and Electric Light Company*, D.T.E. 98-51, p. 30. The functions of the SEC and the Department "are not incompatible, much less in such conflict that [the Department's] duty to review costs pursuant to § 94 is preempted." *Id.,* p. 28.

[11] The Public Utility Holding Company Act of 1935 ("PUHCA") requires that the Securities and Exchange Commission ("SEC") approve KeySpan's merger with Eastern Enterprises. RR-AG-15, Attachment (a) (Order approving the KeySpan/Eastern merger). The SEC also approved the creation of the Service Company to provide administrative and other services to affiliated companies in a cost effective manner. *Id*., Attachment (c). PUHCA requires that the SEC must find that the utilities being acquired "cannot be operated as an independent system without the loss of substantial economies" which can be secured by the control of the holding company and that the "systems under the control of a single holding company is "not so large...as to impair the advantages of localized management, efficient operation, or the effectiveness of regulation." RR-AG-15, Attachment (a), p.15 (SEC merger order). The SEC performs audits of the Service Company to review compliance with SEC guidelines. See, e.g. Exh. AG 1-8 (2001 and 2002 SEC audit results).

[12] The Company's petition filed with the Department contains material errors and inconsistencies. Two key witnesses have made significant revisions to exhibits to correct errors and address issues that should have been resolved prior to filing this case. Exh. KEDNE/ALS-3 & 4 and Exh. KEDNE/PJM-2 (revised). Accounting errors and the unorthodox accounting treatment of certain costs, which have unnecessarily complicated this filing, include accounting errors related to the CRIS conversion and the unusual accounting treatment of certain costs recovered through the Company's CGA. See AG Initial Brief, Section V.B.3. Production, Storage, and Gas Acquisition costs which are made up of O&M, depreciation and return components were booked as Gas costs and, curiously, credited to the A&G expense account. The Company also charged the majority of service company costs to A&G expense accounts rather than to the accounts prescribed by the Department in its Uniform System of Accounts.

Department decides to include some level of these costs, then the Department should order the adjustments recommended by the Attorney General so that these costs are fair, equitable and representative.

In this proceeding the Company presents its first rate filing since its acquisition by KeySpan. The 2002 test year also represents the first year that operations have been fully integrated with the Service Company.[13] Tr. 2, pp. 212-214. It is not clear from the record that the Company has resolved all problems surrounding the transition process, especially problems associated with full compliance with SEC financial disclosure requirements and the allocation of Service Company costs. Exh. AG-1-8, Attachment AG-1-8(a) and Exh. AG-17-33 (original and supplement). The lack of historical performance data demonstrating the successful integration of services provided by the Service Company, the complexities and irregularities of the Company's accounting for costs, and the newness of systems such as the CRIS computer and the Oracle systems developed and implemented since the merger, require the Department to conclude the test year costs are not representative of the rate period, a period that may extend for 10 years of automatic rate escalation.

Tr. 22, p. 2983 and Tr. 23, pp. 3156-3158; Exh. AG-31-6.

[13] Boston Gas, Colonial Gas and Essex Gas have all entered into separate contracts with the Service Company, effective January 1, 2002. Exh. KEDNE/PJM-3. "Exhibit II" to these agreements identifies each client company's service selection based on a menu of general offerings. Not all companies have selected all services. The gas companies have chosen to receive all of the services for the test year. In addition to "Exhibit II" services, the gas companies have amended their service agreements to include some additional activities: Gas Supply, Gas Operations (including Management and Administrative Services, Operations Support Services, Field Services, and T&D System Planning services), and Gas Marketing and Sales Services. The amendment for additional services differs in two ways from Exhibit II. The amendment is a single document specifying a single set of services for Boston Gas Company, Colonial Gas and Essex Gas. EnergyNorth is not a signatory. "Exhibit II" is a separate document for each client company. The amendment, like the service agreement, does not specify a termination date. Exhibit II specifies a term for services.

During the test year the Company incurred costs in excess of $93 million for services performed by the Service Company. Exh. AG-1-2B(8)(a), p. 5. Of that $93 million, $79 million was recorded as expenses. *Id*. The Company's test year cost of service incorporates adjustments to remove approximately $2.2 million of the Service Company charges representing costs not recoverable through rates (memberships and branding), costs the Company deemed incremental to Essex Gas Company ($425,000), and the effect of SEC required cost allocation changes. Exh. KEDNE/PJM-2 [revised], p. 26. In addition, the Company adjusts rate base for computer system costs and related amortization expenses for incremental and non-incremental investments and amortization. Exh. KEDNE/PJM-2 [revised], pp. 31 and 39. The Company's proposed revenue requirement also includes an adjustment that increases test year expenses by $7.3 million for Service Company charges to Colonial that the Company deems are non-incremental. In total, the Company's test year level of expenses includes more than $84 million in Service Company costs before pro forma adjustments ($79 million minus $2.2 million plus $7.3 million). This is approximately 55% ($84 million/$154 million) of the Company's 2002 non-gas operating costs. Exh. AG-1-2B(8)(a), pp. 46-47.

The Company's witnesses have resisted attempts to determine whether the Company has proposed representative costs, the related status and complexities of the Service Company allocations and whether the Company is in compliance with the SEC audit findings. When questioned about the Service Company's compliance with the SEC audit, the Company's witnesses persisted in making either one of two statements: the audit has been completed or the SEC did not require the company to make any adjustments because the adjustments were immaterial.[14] Tr. 2, pp. 232-240 and Tr. 23, p. 3164. Not until the Company responded to RR-AG-78, on August 15, 2003, did the Company admit, based on a conversation with the head of the SEC audit compelled by the Attorney General, that the SEC would be issuing a final audit letter officially "closing the audit upon resolution of all pending matters." *See also* Exh. AG-17-33 (supp.). Whether the SEC officially closes the audit or not, there continue to be unresolved ratesetting issues that the Department should address:

1. The Service Company has reallocated only $28 million of the $97 million identified by the SEC as the amount of corporate governance costs subject to reallocation. Exh. AG-17-33, Attachment 17-33(e), pp. 52-53 and RR-AG-75, pp. 1-6, right hand column (sum of all categories identified by SEC).[15]

2. The SEC raised the issue that only minimal costs were being allocated to the non-utility companies. Exh. AG-17-33 (supp.), Attachment AG-17-33(e), pp. 51 (Finding 19) There is no evidence that the Service Company has attempted to address the problem. To the contrary, the company's reallocation of corporate governance costs actually reduces the non-utility affiliates' allocations. RR-AG-34 (*Compare* THEC (Houston Exploration) G01 allocator to G08, pages 0001 and 0008, and the decrease in allocation of corporate governance costs, last page of RR-AG-34).

3. The Company's reallocation of corporate governance costs excludes Financial Planning costs identified by the SEC . RR-AG-75, p. 2. Included in this category are costs labeled "Merger/Acq Res Plan" (merger/acquisition resource planning).

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[14] The Company has made adjustments to its cost of service for the reallocation of certain corporate governance costs, the reallocation of certain invoices and to reflect the reallocation of costs related to the sale of a subsidiary, Midland Enterprises. The elimination of Midland affected the computation of the Service Company allocators. Exh. KEDNE/PJM-2 [revised], p. 26, Tr. 1, pp. 9-10 and Tr. 2, p. 203. The Company proposed the Midland adjustment to "normalize the test year expense level." Exh. KEDNE/PJM-2 [revised], pp. 2-3, item 4 (cover letter).

[15] The Company identifies and corrects the total of the 2002 corporate governance costs detailed in the SEC/KeySpan audit correspondence. Exh. AG-17-33 (e), pp.52-53. The correct total is $93 million. RR-AG-75. KeySpan reallocates $47 million under the rubric corporate governance expenses, of which approximately $19 million is not associated with the costs and categories delineated by the SEC; therefore the Service Company corporate governance reallocation accounts for only $28 million of the SEC identified costs, leaving over $65 million ($93 minus ($47 minus $19)) apparently out of compliance with the SEC's findings.

The Company's witness testified that these costs represent economic analyses done for the benefit of client companies– at one time these were related to mergers. Tr. 17, pp. 2316-2317 According to the witness, it was agreed that financial planning would not be allocated to the Holding Company. Tr. 23, p. 3164. There is no evidence that the SEC accepts the company's view that the "Merger/Acq Res Plan" costs fall outside **its** definition of costs that should, at least in part, be allocated to the Holding Company.

4. The SEC's audit findings refer to a sample or selection of invoices when discussing the reallocation of specific costs. The Company, after several rounds resisting the recommended reallocation of these costs, agreed to reallocate **identified** invoices rather than reallocating all similar costs. Exh. AG-17-33 (supp.), Attachment AG-17-33 (e), p. 54 (company agrees to reallocate **identified** invoices), pp. 55-64, Finding 21, Item 1 (SEC's selection of certain invoices related to Account 930.2, finding that all of the selected invoices for Shareholder Meetings and Board of Directors expenses should be assigned to the Holding Company).[16]

5. The Service Company does not allocate any costs to Essex (only Service Company costs that are directly assigned to Essex are billed to Essex). According to the Company, the SEC did not object to the lack of allocations to Essex. Tr. 8, pp. 956-958. The SEC audit findings, however, did not show that the SEC ever considered, or was informed of, the lack of allocation to Essex.

The Department retains the power to deny recovery of Service Company costs that it does not find are just, reasonable and consistent with precedent. *Fitchburg Gas and Electric Light Company*, D.T.E. 98-51, p. 30. The SEC has focused on a number of costs it found were not allocated in a manner that is fair and equitable as required by PUHCA, section 13(b). Exh. AG-17-33 (supp), Attachment AG-17-33(e), pp. 48, 52, 58, 69. The Company has not provided any evidence that the adjustments it has made to its cost of service actually reflect a fair and equitable

[16] In communication regarding Finding 21, Item 1 (Shareholder Meetings and Board of Directors expenses), the company states that reallocation of the 2002 amounts are not required, but the company will reallocate identified **invoices**. Exh. AG-17-33 (supp.), Attachment AG-17-33(e), p.63. The Company's witness claims that all Shareholder Meetings and Board of Directors expenses for 2002 were reallocated, but fails to explain why the SEC **and** the Service Company refer to only selected or certain identified invoices. Tr. 17, pp. 2295-2301.

allocation of costs to Boston Gas and that the costs are appropriate under the Department's standards. Therefore, the Department should require the Company to:

1. adjust its cost of service to remove the impact of the reallocation of **all** the corporate governance costs identified by the SEC. Contrary to the Company's interpretation that it only needs to reallocate the costs originally allocated using the G01 allocator, the Department should independently determine that Boston Gas customers should not be burdened with costs for which they receive no proven benefit.

2. reallocate all costs that fall in the categories identified by the sample transactions, and direct the Company to incorporate the reassignments in its accounting systems.

3. develop accounting procedures that incorporate Essex as a discrete entity in the development of the Service Company cost.

B. RATE BASE

1. THE DEPARTMENT SHOULD EXCLUDE FROM RATE BASE IMPRUDENT EXPENDITURES FOR GROWTH-RELATED PLANT ADDITIONS.

The record evidence establishes that the Company imprudently invested capital in revenue producing plant additions that will not provide a return equal to or greater than the return allowed by the Department in D.P.U. 96-50. Shareholders, not customers, should pay for these uneconomic decisions.

The Company calculated an internal rate of return ("IRR") of 18.8% for 36 revenue producing (growth-related) plant investments from 1996 to 2002 that exceeded $100,000 each, for a total of $27 million. Exh. KEDNE/PJM-10; Exh. DTE-4-31; Tr. 7, p. 813. The Company calculated the IRR on the total capital cost for each of the 36 investments prior to commencing construction.[17] Of the 36 investments, 16 projects, totaling $5,941,000, fell below the Company's 9.38% cost of capital set in D.P.U. 96-50.[18] *Id.*; RR-AG-59. Using the Company's current IRR threshold, the number of below-total-capital-investment-rate-of-return revenue producing capital additions grows to 26, totaling $13,366,000.[19]

The Company evaluates whether a growth project will provide a return on its investment before it digs up the ground:

> On every new capital investment we want to make a higher rate of return than allowed in the DTE last rate case, thereby lowering the cost to all our customers. So our revenue on any new capital investment, we want to make more than what was allowed in the rate case.

Tr. 7, p. 814. The evidence shows that the Company invested capital in growth projects where it did not expect to earn a return that was greater than its cost of capital. Exh. KEDNE PJM-10; Exhs. AG-13, 27-38. The Company included the expense of every growth project in the rate base regardless of its expected return on investment. Exh. KEDNE PJM-10; Tr. 7, p. 836.

The below-cost-of-capital growth investments were, from the start, uneconomic,

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[17] The total capital cost included the entire cost of the project-main construction, labor costs, and all fringe benefits. Tr. 7, p. 789.

[18] The work orders for those 16 projects are # 625W, 48652, 46888, 122285, 194128, 38492, 102877, 126093, 153427, 170308, 181446, 194601, 211000,214674, 215994, and 257507. Exh. KEDNE/PJM-10.

[19] The Company stated it currently uses a threshold of 11.75% internal rate of return for revenue-producing residential capital additions, and a threshold of 12.75% IRR for commercial/industrial capital additions. Exh. DTE-4-28; Tr. 7, p. 813. The internal rates of return for residential differ from commercial/industrial "because commercial load is more risky than residential load. When you get a residential customer, you're pretty sure you have them for the next 25 years. Commercial customers come and go, and they might be out of business two years from now and your investment may or may not pan out." Tr. 7, p. 815. The additional ten projects, which total $7,425,088, are work orders # 952Q, 620U, 28507, 31443, 42648, 57965, 75948, 78752, 65725, 68904, 101932, 106700, 168829, 169744, 169907, 199770, 200021, and 93010. Exh. KEDNE/PJM-10. There could be additional imprudent investments below the $100,000 threshold.

imprudent investments that should not be included in the rate base. Far from lowering the cost to all customers, the Company's practice of including uneconomic investments raises the Company's revenue requirement by $568,000 for the 16 projects that fell below 9.38%,[20] and by $1,352,000 for the 26 projects that fell below 12.75%.[21] The Department should exclude from the rate base at least $5,941,000 of the revenue producing plant additions in excess of $100,000 where the initial rate of return was less than the Company's 9.38% cost of capital set in D.P.U. 96-50.

2. THE DEPARTMENT SHOULD REMOVE FROM RATE BASE THE COSTS OF A NON-DISCRETIONARY PROJECT FOR WHICH THE COMPANY IGNORED THE DEPARTMENT'S ORDER TO PERFORM A COST-BENEFIT ANALYSIS OR SHOW COST CONTAINMENT EFFORTS.

The Department has twice ordered the Company to develop a cost/benefit analysis for all non-discretionary, non-revenue producing construction projects in excess of $100,000. *Boston Gas*, D.P.U. 93-60, pp. 35-36; *Boston Gas Company*, D.P.U. 96-50 (Phase I), p. 17 (December 2, 1996). Where a cost/benefit analysis is not applicable, the Department required the Company to show that it sought to contain the cost of the project. *Id.*, p. 17. As a matter of practice, the Company did not calculate the IRR for non-revenue producing plant "because they're non-

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[20] If the additions to utility plant are reduced by $5,941,056, the total rate base is reduced from $627,449,530 to $621,558,474 (Exh. KEDNE/PJM-2, Revision 2, p. 38 of 41), the return on rate base drops to $62,963,873 ($621,558,474 x 10.13%) (*id.*, p. 1A), the total cost of service lowers from $674,203,998 to $673,634,234 (*id.*, Schedule 1), and the revenue deficiency drops from $61,997,247 to $61,429,483 ($673,634,234 - $612,204,751, *id.*), or $568,000.

[21] If the utility plant is reduced by $13,366,144, the total rate base is reduced by $13,336,144 (from $627,449,530 to $614,083,386) (Exh. KEDNE/PJM-2, Revision 2, p. 38 of 41), the required rate of return on rate base drops to $62,206,647 ($614,083,386 x 10.13%) (*id.*, p. 1A), the total cost of service lowers from $674,203,998 to $672,850,008 (*id.*, Schedule 1), and the revenue deficiency (revenue requirement) drops from $61,997,247 to $60,645,257 ($672,850,008 - $612,204,751, *id.*), resulting in a sizable decrease of $1,351,990.

revenue-producing" and performed no other cost/benefit analysis of non-revenue producing plant. Tr. 7, pp. 805-806; Exh KEDNE/PJM-8; Exh. KEDNE/PJM-9.

In the case of the West Roxbury project, Work Order 79111, the Company has not shown how it attempted to control its costs. The street main authorization report shows that the Company intended to add an 800 foot, 12-inch pipe main in 2000 to serve the West Roxbury High School at a projected expense of $87,000, including overhead. Exh. AG-12; Tr. 7, pp. 810-811; Exh. AG 1-19(b). The West Roxbury closing report shows that two and a half years later, the Company finished the project at a cost of $575,541.06. *Id.*; Exh. KEDNE/PJM-8, p. 1. The Company witness agreed at hearing that a project of this size should not take two and half years to complete and was unable to explain the reasons for the delay and $500,000 cost increase based on the opening and closing reports. Tr. 7, pp. 812, 813.

The Company failed to provide the level of detail for the record necessary for the Department to evaluate whether the West Roxbury project costs were "fully monitored and controlled." *Boston Gas Company*, D.P.U. 93-60, p. 35 (1993). A cost overrun of this magnitude is significant; the Company should have investigated the reasons for the excess and demonstrated their attempts to control the project cost before seeking to include the expense in the rate base.[22] Because the Company failed to adequately document and show that it took all reasonable steps to contain this substantial cost overrun, the Department should remove the West Roxbury project cost, $576,000, from the Company's rate base.

[22] A sizable portion of the unexplained project cost consists of a $295,000 labor charge on October 25, 2002 (Exh. AG-12, p. 7), a distribution gas clearing burden charge on October 25, 2002 of $148,000 (*Id.,* p. 9), and a $58,000 permit charge on November 6, 2001, to the MDC Parks Trust Fund (*Id.*, p. 7).

3. The Department Should Disallow The CRIS Computer System Costs Because The Company Has Not Shown That They Were Prudently Incurred.

In 2000, the Company began converting its customer service and billing system ("CSS") to KeySpan's system ("CRIS"). The majority of the costs associated with this conversion were for outside services. The Company has capitalized the associated costs and is amortizing them over ten years. Exh. KEDNE/PJM-1, p. 46. Boston Gas implemented the CRIS system in June 2002. The total cost for the new system, $33.8 million, is allocated among the KeySpan New England Local Distribution Companies ("LDCs") based on the number of meters. Exh. KEDNE/PJM-1, p. 46; Tr. 7, p. 838. The Company's allocation is $23.6 million. Exh. KEDNE/PJM-1, p. 46.

The Company has the burden of demonstrating the prudence of each capital investment proposed for recovery. *Berkshire Gas Company*, D.P.U. 92-210, p. 24 (1992). In prior cases, the Department has directed the Company to (1) use cost-benefit analysis or a similar management tool for all nondiscretionary projects in excess of $100,000; (2) budget all indirect costs as part of its budget authorizations; and (3) support the project authorizations with sufficiently detailed cost-benefit analyses commensurate with the project's complexity and expense. *Boston Gas Company*, D.P.U. 96-50 (Phase I), p. 17, *Boston Gas Company*, D.P.U. 93-60, pp. 35-36. If a cost-benefit analysis was not applicable to a particular project, the Department requires a company to demonstrate that it sought to contain the overall cost of such projects. *Boston Gas Company*, D.P.U. 96-50 (Phase I), p. 17; *Boston Gas Company*, D.P.U. 93-60, p. 35, n. 13. Although the CRIS system is a nondiscretionary project, the Company did not conduct a cost-benefit analysis. Tr. 7, pp. 805-806. Nor has the Company provided any meaningful analysis of the project, including required documentation of cost containment efforts. *Boston Gas Company*, D.P.U. 96-50 (Phase 1), p. 17.

The Department requires that companies either procure outside services by competitive bid or else provide adequate documentation for their decision not to procure services competitively. *Berkshire Gas Company*, D.T.E. 01-56, p. 73 (2001) and *Boston Gas Company*, D.P.U. 96-50, p. 79 (1996). The Company did not comply with this outside services procurement requirement. The Company did not issue a formal Request For Proposal ("RFP") for services necessary to convert the CSS system and data to the CRIS system, rather it merely notified some vendors that it had project work available. Tr. 21, p. 2840. The first firm the Company hired, DMR Consulting, was not adequate and the Company later had to hire a more experienced firm, Technology Consulting Associates ("TCA"). Exh. AG-6-87. Neither DMR Consulting nor TCA appears on the list of vendors solicited by the Company in lieu of a formal RFP. Exh. AG-6-87 (original and supplement). So, even after hiring an unqualified vendor, the Company failed to go out to bid for services. Tr. 21, p. 2842-43.

With a project of this magnitude and importance, the Company should not only have gone out to bid, but it also should have made every effort to assure that the selected vendors had the highest qualifications and experience. There is no evidence on the record to show that the Company took this approach to staffing the CRIS conversion project. In fact, the record indicates that there was no competition for the project and therefore no meaningful assessment of qualifying candidates.

The Company experienced several significant problems with the conversion and implementation of the new billing system, including errors that resulted in late payment charges not being billed, misleading reports of ECS data, missing write-off recovery information for three months of the test year and faulty weather normalization data. Tr. 6, pp. 690-691, p. 701; Tr. 8, pp. 965-966; RR-AG-6; RR-DTE-22. The Department should order the Company to competitively solicit a qualified independent auditor to audit the CRIS system as implemented for Boston Gas. The independent auditor should determine the accuracy of bills since the conversion and the ability of the system to accurately generate bills in compliance with the Department's orders regarding automatic adjustment clauses and reconciling mechanisms. The audit should include a comprehensive assessment of the computer programs, software, technical support, maintenance, error reporting systems, internal controls and verification procedures, and hardware employed by the system.

For many customers, the billing system produces the only direct contact they have with the Company. Customers rely on the accuracy of the system to render correct bills. The Company relies on the CRIS system to generate normalized revenues and bill determinants on which the proposed revenue increase and distribution rates are based. The Company proposes to rely on the system, moreover, to automatically adjust, in real time, customer bills for normal weather as part of its proposed weather stabilization clause. The Department should not approve the weather stabilization clause, among other reasons discussed *infra*, because the CRIS system has not shown that it is sufficiently accurate to merit the very high degree of confidence necessary for these adjustments. CRIS' real time adjustments would eliminate the ability of the Department's consumer representatives and customers to verify individual bills from meter data and tariff provisions.[23]

The Company has not established that the $33.8 million investment in the CRIS system was a prudent expenditure.[24] The reliability and accuracy of the system are in question. The Department should not allow the Company to include the cost for the CRIS system in rates.

4. THE DEPARTMENT SHOULD REDUCE THE AMORTIZATION FOR INTANGIBLE PLANT BY $266,000.

The Company proposes to recover (1) a test year amortization expense for intangible plant (Exh. KEDNE/PJM-2, Revision 2, page 31 of 41, line 3); (2) an intangible amortization adjustment of $1.39 million, (Exh. KEDNE/PJM-2, Revision 2, page 31 of 41, line 9); and a 2003 non-informational software amortization of $320,000 (Exh. KEDNE/PJM-2 Supp., p. 164). All of these items are based on nine software packages that will be fully amortized by June 30, 2004. Exh. KEDNE/PJM-2 Supp., p. 164; RR-AG-28.[25]

The Department allows cost of service recovery for the unamortized intangible plant remaining at the time of the Department's order, not the full annual amortization amount of $320,000 as the Company proposes. *Boston Gas Company*, D.P.U. 96-50 (Phase I), pp. 100-101 (December 2, 1996). Under the formula prescribed in D.P.U. 96-50, the Company's unamortized

[23] As discussed in the Weather Stabilization Clause section, *infra*, there is serious doubt about the ability of the system to produce accurate bills given the errors encountered in discovery responses.

[24] The costs associated with the system conversion include "extraordinary" bonus payments. Tr. 25, pp. 3502-3506. See also RR-AG-100. The Department must determine the propriety of making additional payments to Company employees and whether these payments are consistent with reasonable cost containment efforts.

[25] Although the Company described these software packages as five-year intangible plant commencing December 31, 1999, the Company is actually scheduled to complete amortizing the software by June 30, 2004. Exh. KEDNE/PJM-2 Supp., p. 164.

non-informational software balance was $421,000 at the end of the test year. The Company is scheduled to amortize an additional $266,000 ($319,722 x 10/12) by the date of the Department's order. The remaining balance as of November 1, 2003 (the date of the Department's order) will be $155,000. Exh. KEDNE/PJM-2 Supp., p. 164. The Department should reduce the Company's amortization by $266,000.

The Department, if it chooses to use the same formula as in D.P.U. 96-50, will create a reserve for future amortizations in the cost of service because the nine software programs will have been fully amortized by June 30, 2004, but the Company will continue to collect $155,000 each year from rates throughout the term of the PBR, if the Department orders a PBR. Annual recovery would permit the Company to recover its expenses from ratepayers many times over. The Department should abandon the formula used in D.P.U. 96-50 and, instead, should allow the company to recover its remaining unamortized intangible plant balance over the term of any PBR. This would spread the expense recovery more efficiently and would better adhere to the principle underlying the Department's precedent. Applying this alternate formula, the Department should reduce the Company's amortization expense adjustment of intangible plant by an additional $288,813.[26]

5. THE DEPARTMENT SHOULD DEDUCT FROM RATE BASE THE TEST YEAR-END BALANCE OF CUSTOMERS' CONSTRUCTION ADVANCES.

Basic ratemaking theory and the Department's longstanding policy require that customer-provided cash advances be used as a deduction to rate base when determining the cost of service

[26] The calculation is: $319,722 [Company adjustment]- ($154,545[unamortized balance] ÷ 5 [PBR term]) = $288,813.

to set rates. *Boston Gas Company*, D.P.U. 96-50 (Phase I), p. 390 (the Department ordered that rate base deductions would include Reserve for Deferred Income Taxes, Unamortized ITC – Pre-1971, Customer Deposits, Deferred Service Contract Revenue, and Unclaimed Funds); *Fitchburg Gas & Electric Light Company*, D.T.E. 02-24 / 02-25, p. 66 (2002), *citing Hingham Water Company*, D.P.U. 1590, p. 10 (1984) ("refundable construction advances are considered by the Department as an offset to rate base"). Although the Company originally proposed to deduct $50,855 in Customer Construction Advances from its rate base, it eliminated the deduction in hearings, claiming that since the advances were "refundable" to customers, they should not be deducted from rate base.

For each and every advance, however, the Company has those funds available for its use for some period at no cost to the Company. Similar to the test year-end balance of accumulated deferred income taxes that the Company collects from its customers in advance of their payment to the United States Treasury, the Company holds those dollars temporarily at zero cost, and then pays them out at some future time. The Customer Construction Advances should not be treated differently from any other zero cost funds provided by customers. Therefore, the Department should deduct the test year end balance of Customer Construction Advances from the Company's rate base used in determining rates.

C. REVENUE ADJUSTMENTS

1. THE DEPARTMENT SHOULD REJECT THE COMPANY'S PROPOSED SPECIAL CONTRACT REVENUE ADJUSTMENTS BECAUSE THERE HAS NOT BEEN THE LOSS OF A LARGE CUSTOMER WITH REVENUE BEYOND THE NORMAL EBB AND FLOW.

The Company credits revenues from firm non-core transportation agreements ("special contracts") to the cost of service and allocates these revenues to the various rate classes using the rate base allocator. Tr. 6, pp. 707-708. The Company proposes to reduce test year special contract revenues to eliminate the test year revenue ($3.7 million) from one contract involving Mystic Station that is scheduled to terminate March 1, 2004, a point prior to the midpoint of the rate year (May 1, 2004). The Company also annualizes the revenues from another special contract that began during the test year, yielding a net reduction of test year special contract revenues of $3.4 million. Exh. KEDNE/AEL-1, p. 10.

The Department generally does not allow revenue adjustments for the gain or loss of customers unless the change to test year revenues is known and measurable and constitutes a significant adjustment outside of the "ebb and flow" of customers. *Fitchburg Gas and Electric Light Company*, D.T.E. 99-118, pp. 17 (2001); *Fitchburg Gas and Electric Light Company*, D.T.E. 02-24/25, p. 80 (2002). The Department should reject the Company's proposed adjustment because it is not a known and measurable change and it does not constitute a significant adjustment as required by the Department.

The Company's revenue loss is not known and measurable. Although the termination date for the contract is March 1, 2004, this contract has a long history of amendments to extend the term of the agreement. *See* Exh. AG-1-99. The original contract was scheduled to terminate on December 1, 2000, and was extended five times throughout the life of the contract. Exh. AG-1-99, p. 413, pp. 452-458, p. 461, p. 463 and p. 466. The Company has provided no evidence that the contract will not be extended again, particularly in light of the fact that the majority of the use under the contract is for the Mystic 7 Unit which will remain in service for the foreseeable future.[27] Indeed, the Mystic 7 Unit may still continue as an Interruptible Transportation ("IT") customer. RR-AG-25. Also, the amendments to the contract indicate a recent increase in estimated use compared to prior estimates. Exh. AG-1-99, p. 460 and p. 465.

The Company's anticipated revenue loss does not constitute a significant adjustment beyond the "ebb and flow" as required by the Department. The Company's witness testified that the revenue loss represents only about 1.2% of the Company's firm margin (revenue net of gas cost). Tr. 7, p. 778. This is a small loss compared to the ones in the recent Fitchburg cases, where the Department allowed adjustments to annualize the losses and gains of revenues from single customers. Princeton Paper generated approximately 8.4 percent of the company's total electric base distribution revenues and 20 percent of its total electricity demand, while Newark American contributed almost 7 percent of Fitchburg's base electric distribution revenues. *Fitchburg Gas and Electric*, D.T.E. 99-118, p. 20; *Fitchburg Gas and Electric Light Company*, D.T.E. 02-24/25, pp. 80-81. The Company's loss of its customer here does not affect its revenues nearly as dramatically as in the two *Fitchburg* cases. The Company is not even losing Mystic Station as a customer. The same customer will continue to receive distribution service from the Company, through an arrangement with the third-party gas supplier, at the same site. At most, older generation will merely be replaced by two new units that will use more than 3.5

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[27] All generating units must receive NEPOOL approval before being retired. According to the ISO-NE website Mystic 7 has not been listed as having applied for the necessary approvals.
http://www.iso-ne.com/FERC/filings/Agreements/Composite_RNA_94th_3-14-03.pdf
Refer to Section 18.4.
See also: http://www.iso-ne.com/smd/transmission_planning/Status_of_18.4_Applications/All_Approved_or_Withdrawn_184_Applications_updated_030728.pdf Provides the most recent listing of Section 18.4 applications and their status. Pages 57-58 list Mystic 4, 5, 6 and New Boston 1 on the report dated August 7, 2003.

times the volumes delivered to the customer during the test year.[28] Tr. 6, p. 615. This is not the kind of change that constitutes the loss of a large customer under Department precedent. The reason the Company projects a net revenue loss of over $3.4 million per year is that the Mystic 8 and 9 supplier has contracted to pay a rate that is 1/18 of the rate paid under the Mystic 7 contract on a per MMBtu basis. Compare AG-1-99, page 465 (Mystic 7), column 8 to page 355 (Mystic 8 and 9), column 7 for 2002. Tr. 7, p. 778.[29]

The Company has not made clear on the record in this case whether the new Mystic contract is the result of an exchange, discounting service to one customer with whom the Company has other contractual relationships,[30] or whether there is some legitimate cost basis underlying the Mystic 8 and 9 agreement when compared with the Mystic 7 agreement. At a time of rising gas prices, firm core ratepayers should not have to pay higher rates, without any showing of ratepayer benefit, because the delivery price of gas paid by a special contract customer has dropped by almost 95 percent. For these reasons, the Department should not allow the proposed revenue adjustment.

These issues, the overall magnitude of the Company's special contracts and the

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[28] The significant increase in the volumes is due to the capacity of the new generating units (1,700 MW Mystic 8 and 9) and the fact that they are dependent on natural gas for fuel. The Mystic 7 unit (550 MW) is capable of burning both gas and oil. 2003 CELT Report available on ISO-NE website: http://www.iso-ne.com/Historical_Data/CELT_Report/2003_CELT_Report/Excel_and_Word_Files/

[29] Although the Company off-sets the test year revenue loss for Mystic 7 with an estimate of annual revenues from transporting gas to the new Mystic units, the revenues for significantly more volumes amounts to a little more than 25 percent of the test year revenues for the Mystic 7 contract.

[30] The Company not only has another special contract with Distrigas but also purchases LNG from Distrigas. Exh. AG-17-43, Attachment (a).

significant discounting of rates compared to tariffed rates[31] for distribution-only service, however, raise questions regarding what policy the Department should adopt for distribution service contracting. The Department should review the continuing need for special contracts and determine the best contracting policies and practices to develop a single set of objective standards for all utilities. The Department should eliminate any favorable treatment being afforded to any special contract customer or class of non-tariffed customers.

D. EXPENSES

1. THE DEPARTMENT SHOULD REQUIRE THE COMPANY TO CONTINUE REFLECTING ITS INVESTMENT TAX CREDIT AMORTIZATION.

Prior to the Tax Reform Act of 1986, regulated utilities earned investment tax credits ("ITCs") equal to 10% of qualifying investments. Regulated utilities are still amortizing on their books the ITCs earned on investments before 1987. The Internal Revenue Code, in effect, required normalization accounting for ITCs generated after 1970. Regulated utilities generally could elect either Option 1, with a rate base deduction for the unamortized balance of ITC but no amortization of ITCs reflected in the cost of service; or Option 2, with ratable amortization of ITCs included in the cost of service but no rate base deduction for the unamortized balance of ITC.

The Attorney General's witness, Mr. Effron, proposed an adjustment to the Company's calculation of income taxes:

[31] Evidence shows that had the special contract customers been on tariffed rates, test year revenues would have been more than $46 million greater than they were under the special contract rates. The result is that more than a 70% discount is being provided to the special contract customers, with a discount greater than 85% going to Distrigas (including service to Mystic 8 and 9). Tr. 6, pp. 663-664.

> In the 2002 test year, the Company recorded $842,000 of investment tax credit amortization. The calculation of income tax expense on Exhibit KEDNE/PJM-2, Page 35 does not reflect that amortization of investment tax credits. It should. Inclusion of the investment tax credit amortization in the income tax calculation reduces the pro forma income tax expense by $842,000 and the revenue requirement by $1,385,000.

Exh. AG-42, p. 21

The Company's witness, Mr. McClellan, opposed inclusion of the investment tax credit amortization in the income tax calculation, claiming that Boston Gas Company is an "Option 1" company for post-1970 ITCs by default because no formal election had ever been filed with the IRS. Tr. 25, pp. 3512-3513. He reflected the unamortized investment tax credits as reduction to rate base, rather than reflecting the investment tax credit amortization as a credit to income tax expense. Exh. KEDNE/PJM 14, pp. 6-7.

Mr. McClellan admitted, however, that he could find no record of the Company actually making a formal election for Option 1. He further admitted that if Boston Gas were an Option 1 company and the Department included the amortization of ITC in the calculation of income taxes for cost of service purposes, that would be a violation of the normalization requirements of the Internal Revenue Code. Tr. 25, p. 3517. The Company has never been cited by the IRS for any such violations. *Id*.

Mr. McClellan was unable to produce any evidence that the Department ever treated Boston Gas Company as an Option 1 company. Instead, all available evidence shows that the Department has always treated Boston Gas Company as an Option 2 (ratable amortization of post-1970 investment tax credits). The Department included the amortization of investment tax credits in the calculation of income taxes in D.P.U. 96-50. Tr. 25, p. 3513. Mr. McClellan contends that both the Company and the Department were "wrong" in that case, because they each reflected both the rate base deduction and the amortization of ITC. The rate base deduction for unamortized ITC in D.P.U. 96-50 was only $154,998 and was clearly labeled "Unamortized ITC – **Pre 1971**" (emphasis added). The small size of that rate base deduction confirms that the label was correct, and the deduction pertained only to the pre-1971 ITC, not the post-1970 ITC. There was no error either by the Company or the Department in the treatment of ITC in Docket No. 96-50. The Department also included the amortization of ITC in the calculation of income taxes in both D.P.U. 93-60 and D.P.U. 88-67. Tr. 25, pp. 3515-3516.

The Department has consistently treated Boston Gas Company as an Option 2 company and there is no indication that treatment is inconsistent with any election made (or, for that matter, not made) by the Company. The Company has offered no reason why the Department should change the treatment of post-1970 ITC it has used for **at least** the last fifteen years. Accordingly, the Department should correct the Company's calculation of income tax expense to include investment tax credit amortization in the amount of $842,000. This adjustment reduces the pro forma income tax expense by $842,000 and the Company's revenue requirement by $1,385,000.

2. THE DEPARTMENT SHOULD REDUCE THE COMPANY'S PRO FORMA PENSION EXPENSE BECAUSE IT IS UNREASONABLE AND ABNORMAL.

Boston Gas Company is proposing to include in its cost of service a pro forma pension expense of $18,085,000, an increase of $11,855,000 over the actual pension expense booked by the Company in the 2002 test year. Exh. KEDNE/PJM-2, p. 12.[32] The Department should reduce the Company's pro forma pension expense because it is excessive, whether measured by the reasonably expected normal level of cash contributions to the pension fund or by the accrual for the periodic pension cost pursuant to Statement of Financial Accounting Standards ("SFAS") 87.

Mr. Effron explained why the Company's determination of pro forma pension expense is not reasonable:

> In 2001, the contribution to the pension fund was $19,000,000. In 2002, the contribution to the pension fund was $44,460,000. This followed a period of four years of zero contributions to the pension fund. Clearly, the contributions in 2001 and 2002 included a catch up for the zero funding in the earlier years. While, it is true that the Company did include one of the zero years in its three-year average, the $21.1 million still appears to be well in excess of any reasonable estimate of the annual pension cost that the Company will incur on a normal, ongoing basis.

Exh. AG-42, p. 14.

He then elaborated on why the $21.1 million estimated annual pension cost was excessive:

> First, it is well in excess of the historic level of cash contributions based on any average that goes back farther than the three (years) ended in 200(2). Further, in response to Information Request AG-11-13, the Company provided details of its estimated pension cost for 2003. That response shows an estimated pension cost of $17,366,000 for 2003, calculated pursuant to Statement of Financial Accounting Standards 87 ("SFAS 87"). However, even that estimate appears to be on the high side.

Id.

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[32] The Company based its proposed pro forma pension expense on the average of the cash contributions for the years 2000 – 2002, $21,153,000. Of this amount, $18,085,000 is charged to operation and maintenance expense, with the remainder being capitalized or charged to other non-operating accounts.

Using what he described as highly conservative assumptions, Mr. Effron calculated that a reasonable estimate of the periodic pension cost for 2003 pursuant to SFAS would be approximately $12.6 million (Exh. AG-42, p. 16) based on the funded status of the pension plan as of the end of 2002 and the parameters assumed by the Company. This calculation further illustrates the excessive nature of the $21.1 million estimated pension cost calculated by the Company.

Mr. Effron proposed an alternative method of determining the pro forma pension expense:

> I recommend that the average cash contribution to the pension plan for the five-year period 1998 – 2002 be used to determine the pro forma pension expense. As the contributions in 1998 and 1999 were also zero, using a five-year average would spread the contributions in 2001 and 2002 over five years rather than the three years proposed by the Company. This would mitigate the effect of catch-up contributions made in 2001 and 2002. Although the contribution in 1997 was also zero, I believe that use of a five-year average is reasonable in the circumstances.
>
> In addition, use of a five-year average of cash contributions to the pension plan is consistent with the method of calculating pension expense approved by the Department in D.P.U. 96-50. The Company has provided no compelling reason why the practice of using a five-year average, as previously approved by the Department, should be changed at this time. Finally, the five-year average of cash contributions to the pension plan approximates the estimated periodic pension cost for 2003 pursuant to SFAS 87, as I have calculated it.... This should minimize the difference between the pension expense recovered in rates and the pension expense recorded by the Company on its books, which reflect generally accepted accounting principles.

Exh. AG-42, pp. 16-17.

The average cash contribution for the five-year period 1998-2002 was $12,692,000. After removing the capitalized amount, 14.5%, the pro forma pension expense would be $10,851,000, which is $7,234,000 less than the pro forma pension expense calculated by the

Company, but still represents a significant increase over the pension expense recorded by the Company in 2002. Exh. AG-42, p. 17.

The method used by Mr. Effron to calculate pro forma pension expense is consistent with Department precedent as established in the Company's last base rate case, D.P.U. 96-50 (Order, p. 81). The Company offered no rebuttal to the pro forma pension expense proposed by Mr. Effron. The Department should reduce the Company's pro forma pension expense by $7,234,000, to $10,851,000.

3. THE DEPARTMENT SHOULD REJECT THE COMPANY'S PENSION/PBOP RECONCILIATION ADJUSTMENT CLAUSE.

Boston Gas Company has asked that the Department to approve a Pension/PBOP Reconciliation Adjustment Clause ("reconciliation mechanism"). The reconciliation mechanism would reconcile the actual pension expense recorded by the Company pursuant to SFAS 87 to the pension expense included in rates in this proceeding. Any difference would then be collected from or refunded to customers, with carrying charges on the cumulative balance of any over or under recovery, through an annual surcharge to the Company's base rates. The mechanism also would include carrying charges, at the overall authorized rate of return, on the prepaid pension balance carried on the Company's balance sheet.

a. If The Department Allows The Company To Shift Pension And PBOP Volatility Risk To Ratepayers Through The Proposed Reconciliation Mechanism, Then It Should Make A Corresponding Reduction To Reflect A Lower Cost Of Common Equity.

Since the Department already includes pension costs in base rates, the Company's allowed return on equity includes compensation for any risk associated with the volatility of those costs. The Company's proposal, by itself, would decrease the Company's cost of capital, including its cost of equity, since it would shift the risks of the changes in pension costs from the shareholders to ratepayers. The Attorney General's expert witness, David Effron, testified that "[i]t would be inappropriate to incorporate the proposed reconciliation mechanism without an adjustment to the cost of service to recognize the reduced risk of the Company's common equity." Exh. AG-42, p. 19. The Company's proposal is deficient because it does not propose any reduction in the cost of equity as result of the reduction in risk to investors.

Indeed, the Company's witness, Mr. Moul provided support for this principle in his rebuttal testimony, "That is to say, in the long run, investors have not regarded pension costs any differently from other cost-of-service items that are fully recoverable from customers." Exh. KEDNE/PRM-4, p. 2. If, however, pension costs are treated differently, and the risk of any volatility associated with those costs is shifted from investors to ratepayers, then the risk to investors is obviously reduced, and the reduction in risk will be reflected in the cost of equity.

Mr. Moul is correct that the appropriate risk premium has not been precisely identified. That is because the Company has failed to do so. If the Company had provided evidence of the volatility of its pension costs, then a determination of the appropriate risk premium may have been possible. Having failed to provide any quantification of volatility or the risk to investors posed by such volatility, the Company cannot now argue that there is no such risk. If there is no such risk, then no reconciliation mechanism is warranted. If such risk does exist in the absence of a reconciliation mechanism, then the approval of such a mechanism would eliminate the risk or, more precisely, would shift the risk to customers. The reduction in risk to investors must be accompanied by a reduction in the cost of common equity. The Attorney General opposes the reconciliation mechanism. If, however, the Department approves the Company's proposal, the Attorney General recommends that the authorized return on equity be reduced by 50 basis points (0.50%) from what the authorized return would be in the absence of the reconciliation mechanism. Tr. 26, pp. 3559-3561.

b. The Company Has Not Shown That Its Proposal Is Necessary To Avoid Financial Impairment.

The Company's financial witness, Joseph F. Bodanza, described the reconciliation mechanism as being "designed to minimize distortions in the Company's financial reports that occur as a result of extreme volatility in pension contributions and expenses." Exh. KEDNE/JFB-1. However, as explained by Mr. Effron:

> As a general matter, reconciliation mechanisms are contrary to sound ratemaking practices, as such mechanisms tend to either reduce or eliminate incentives to control costs. The Company presents its proposal as a reconciling mechanism that would address the volatility of pension costs and mitigate potential financial impairment resulting from such volatility. However, the Company has not provided any measurement of the volatility of pension costs or any measurement of how the magnitude of changes in pension costs relate to its overall revenue requirements; nor has the Company compared the magnitude or volatility of pension costs relative to other costs for which there is no adjustment mechanism.

Exh. AG-42, p. 18.

Thus, while the Company claims that the reconciling mechanism would address the volatility of pension costs and mitigate any potential financial impairment resulting from that volatility, it has not provided (1) any measurement of the volatility of pension costs, (2) any measurement of how the magnitude of changes in these expenses relate to overall revenue requirements, (3) any principled distinction between the magnitude or volatility of pension costs and other costs for which there is no adjustment mechanism, or (4) any data or analysis that establishes the potential for the volatility of the pension expense to impair its financial integrity. Mr. Effron stated that:

> While it is true that changes in … assumptions or changes in the funded status of the plan can cause pension expenses to fluctuate, just about all other expenses included in the Company's base rate cost of service are also subject to fluctuation. The Company has not explained why pension costs should be treated differently from these other expenses that go into the base rate revenue requirement. Further, the Company has not presented any analysis showing that the fluctuations in pension costs are of such a magnitude that they have the potential to impair its financial integrity.

Id.

Further, approval of the proposed reconciliation mechanism is not necessary to avoid a charge to equity, through other comprehensive income, to recognize an "Additional Minimum Liability" or to write off the prepaid pension asset. As Mr. Effron testified:

> [T]he Department has always permitted recovery of reasonable and prudent pension expense through the cost of service. Thus, to the extent that the Company's pension costs are reasonable and prudent, there is reasonable assurance that the Department will establish rates that are adequate to generate revenues that will recover those costs. Accordingly, pursuant to Statement of Financial Accounting Standards No. 71, Paragraph 9, the Company can book a regulatory asset to offset the Additional Minimum Liability, even in the absence of a reconciliation mechanism, and should not have to write off the prepaid pension asset.

Exh. AG-42, pp. 19-20.

In summary, the Company has provided no quantification of the volatility of pension expense on reported earnings, nor has the Company established that approval of the proposed reconciliation mechanism is necessary to avoid write-offs. The Company, therefore, has not shown that its proposal is needed to avoid financial impairment.

c. The Department Should Reject The Proposed Pension Adjustment Mechanism Because It Includes Improper Elements, Is Improperly Calculated, and Does Not Require The Company To Make Any Contributions To The Employee Trust Funds.

Mr. Effron testified that the Company's proposed reconciliation mechanism is also defective in several specific ways. Exh. AG-42, pp. 20-21. First, the Company's proposal includes recovery of carrying charges on the net prepaid pension balance carried on the Company's balance sheet. The Department generally has not included prepaid pension balances relating to differences between SFAS 87 expense and cash contributions in utility companies' rate bases. Exh. AG-42, p. 20. Thus, allowing recovery of carrying charges on the prepaid pension balance in the reconciliation mechanism would be inconsistent with the Department precedent of denying recovery in the base rates through the return on rate base. *Id.*

Mr. Effron also stated that the Company was not correctly measuring the cash required by investors to cover the difference between the actual recovery of pension expense in rates and cash disbursements to the pension plan. He explained that the prepaid pension balance reflects the difference between the pension cost pursuant to SFAS 87 and cash contributions to the pension plan, not the difference between the pension expense recovered in rates and cash contributions to the pension plan, as the Company proposes. Exh. AG-42, pp. 20-21.

Finally, the notes to the Company's financial statements, the same financial statements from which the prepaid pension cost was taken, indicate that there was a net liability of $52,355,000 for accrued post-retirement benefits other than pensions ("PBOP") as of the end of 2002. It would be inconsistent to recover a return on the prepaid pension cost without any offset for the accrued PBOP liability. Exh. AG-42, p. 21.

The Company's proposal does not require it to make any contributions to its pension trust funds. That is, there is no requirement that either the amount presently in base rates or the additional amounts recovered through the reconciliation mechanism actually be contributed to the trust funds. In other words, it would be free cash to the Company that could go to the Company's shareholders.

The Department should reject the proposed reconciliation mechanism because it (1) is unnecessary to avoid any potential financial impairment, (2) bases cost adjustments on indeterminable levels of recovery from customers, (3) would recover costs in a manner that is internally inconsistent and is also inconsistent with Department precedent, and (4) does not require that any of the amounts so recovered be used for cash contributions to the trust funds.

4. THE DEPARTMENT SHOULD EXCLUDE $1,637,000 IN INCREMENTAL LEASE EXPENSES BECAUSE THE COMPANY HAS NOT SHOWN ANY NET RATEPAYER BENEFIT.

The Company more than tripled its property lease expenses when it moved its primary offices from One Beacon Street, Boston and Norwood to 52 Second Avenue, Waltham, increasing the total by approximately $1,637,000.[33] The Company claims that the move to Waltham is in the ratepayers' interest because it allowed the Company to consolidate its workforce into one place. Tr. 8, pp. 910-911.

The Company has not demonstrated that net benefits to ratepayers resulted from the move to Waltham. Even after the Waltham move, not all employees are together in Waltham; much of the Company's marketing department is still scattered in various other locations. RR-AG-8. The move also has led to litigation with Renaissance, the previous tenant holder, over the use of signage space at the top of the Waltham premises. Exh. AG-21-19. The Company's property insurance expenses increased dramatically because of the new location and the Company's increased square footage rental. The Company has not shown that consolidating the workforce is worth the added cost to ratepayers. The Company has presented no data or analysis showing that savings exceed the substantial increase. For these reasons, the Department should remove the incremental increase in property lease expense resulting from the Waltham rental, $1,637,000.

5. THE DEPARTMENT SHOULD EXCLUDE $11,547,007 OF SALES PROMOTION EXPENSE FROM THE COST OF SERVICE BECAUSE THE COMPANY DID NOT DEMONSTRATE THAT THE FREE BOILER AND TRADE ALLY PROGRAMS BENEFIT RATEPAYERS.

The Company seeks to include $11,547,007 as sales promotion (customer incentives) expenses in DTE Account 912. Exh. AG-23-1.[34] The Company claims that this expense should

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[33] The total lease and associated operating expense for the Waltham property is $2,362,000; the property lease expenses for the One Beacon Street and Norwood properties for the test year were $725,000 (Exh. KEDNE PJM-2, Revision 2, page 14 of 41, line 4).

[34] DTE Account 912 does not include advertising expense, which is recorded in DTE Account 913 and discussed in a separate section in this brief. The Company states it is seeking to recover $11,547,007 in Account 912 "demonstration and selling expense" (sales promotion expense) and $1,751,879 in

be included in the cost of service because its combined capital investments and promotional expenses result in an aggregate internal rate of return ("IRR") of 18.8% for 2002 and satisfies the Department's requirement for a cost benefit analysis of promotional expenses. Tr. 25, pp. 3438, 3440; Exh. KEDNE/PJM-9; Exh. MOC-1-5.[35]

The Department should exclude at least $11,547,007 from the cost of service for sales promotional expenses because the Company failed to perform an adequate cost-benefit analysis. To recover these expenses under Department precedent, the Company has to demonstrate that the promotion expenses resulted in net benefits to ratepayers. *Berkshire Gas Company*, D.T.E. 01-56A, p. 65 (2002); *Berkshire Gas Company*, D.P.U. 92-210, p. 103 (1993); *Bay State Gas Company*, D.P.U. 92-111, pp. 191-193, 201-202 (1993); *Berkshire Gas Company*, D.P.U. 90-121, pp. 133-134 (1990). The Company's showing is inadequate because (1) the combined capital investment/promotion analysis hid the true effectiveness of the sales promotion programs; (2) the Company did not include all sales promotion costs in its IRR calculation; (3) the Company did not analyze the cost of adding customers on the system; and (4) the Company failed to remove sales promotion costs associated with conversions from electricity to oil.

The Company's analysis masked the cost effectiveness of its sales promotion costs by combining them with its 2002 growth-related capital investments and then calculating the

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Account 913 "advertising expense," for a total of $13,298,886 Exh. AG-23-1; Exh. KEDNE/PJM-2, Revision 2, page 24 of 41. The Company, however, also claims it is seeking approval for $13,026,308 in sales promotional expense (Exh. MOC-1-2(a)), creating an unreconciled difference ($272,578). For purposes of this brief, the Attorney General assumes $11,547,007, as reflected in Exh. AG-23-1, is the appropriate figure for the Company's non-advertising sales promotion expense.

[35] The Company combined its direct and indirect costs of capital additions with sales promotion costs, and then calculated an aggregate IRR for the combined amount by year. Tr. 25, p. 3438.

internal rate of return. Exh. KEDNE/PJM-9. The Company's combined economic analysis fails to provide the Department with the per capita cost effectiveness comparison of promotional expenses alone that the Department mandated. *Berkshire Gas Company*, D.T.E. 01-56A, pp. 65-66.[36] Without a separate cost-benefit analysis for sales promotion expense, the Department cannot evaluate whether $11.5 million spent in 2002 for promotional expenses provided net benefits to ratepayers.

The Company asserts that its analysis of promotional costs includes "Promotional Costs (i.e. Burner/Furnace Program)" and "the costs for incentive conversion programs." Exh. KEDNE/PJM-9; Exh. DTE-4-27. The Company included only $5.9 million, however, or just over half of the $11.5 million total sales promotion costs in its 18.8% IRR calculation. Exh. DTE-4-27. Including the full amount of the sales promotion costs will reduce the IRR percentage. *Id*. Also, Department precedent mandates that the Company analyze the cost of adding customers on the system as part of its cost-benefit analysis of promotional costs. *Berkshire Gas Company*, D.T.E. 01-56A, p. 66, n. 20. The Company failed to evaluate that cost.

Finally, the Company did not break out the Account 912 sales promotion costs associated with the 1,034 residential and commercial/industrial conversions from electricity. Exh. MOC-3,

[36] In *Berkshire*, the Company submitted the costs of its rebates and free boilers, furnaces, water heaters and other customer incentives ($325,433), together with its expected margins (cost - $892 per customer; annual net margin - $494 per customer). *Berkshire Gas Company*, 01-56A, p. 65. The Department held that "the Company's marketing program does not provide net benefits to ratepayers" and rejected the Company's request. *Id*., p. 66. Here, the Company spent nearly thirty-six times the amount Berkshire spent on customer incentives but did not provide the net marginal return. The Company witness testified at hearing that he was not aware of the Department's order in *Berkshire* on incentive programs. Tr. 25, p. 3439.

p. 2.[37] The Department both by statute and precedent must exclude from the cost of service those sales promotion expenses that encourage ratepayers to switch from one Department-regulated industry (*e.g.* electricity) to another. G.L. c. 164, §33A;[38] *Berkshire Gas Company*, D.P.U. 90-121, pp. 133-134 (1990) (holding that for an advertisement to be included in the cost of service "there must be an 'explicit' showing that [the] promotional advertising demonstrates an explicit reference to non-regulated energy sources" and excluding advertisements for gas stoves from cost of service because they compete with electric ranges).

For these reasons the Department should exclude $11,547,007 from the cost of service.

6. THE DEPARTMENT SHOULD REMOVE FROM THE COST OF SERVICE AN ADDITIONAL $670,000 OF MISCATEGORIZED ADVERTISING EXPENSES.

The Company seeks to recover $1,752,000 in advertising expense it paid during the test year. Exh KEDNE/PJM-2, Revision 2, p. 24 of 41. The Company removed $641,000 as an adjustment for image, informational, and miscellaneous advertising, leaving a balance of roughly $1,110,000 in the cost of service. *Id.*; Exh. AG-1. The Company, however, miscategorized many of its advertising expenses and, consequently, overstated its allowable advertising

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[37] This represents 8.2% of the Company's total number of conversions for 2002. The conversion breakdown is: Oil 10,693; Electric 1,034; "other" 827; and total 12,554. Exh. MOC-1-3, p. 2.

[38] "No gas or electric company regulated by the department under this chapter may recover from any ratepayer of such company any direct or indirect expenditure by such company for promotional or political advertising as defined in this section."

"For the purposes of this section, the following words and phrases shall have the following meanings:

'Promotional advertising', any advertising for the purpose of encouraging any person to select or use the service or additional service of a utility regulated by the department, or the selection or installation of any appliance or equipment designed to use such utility's service." G.L. c. 164, § 33A.

expenses. The Department should remove an additional $670,000 from the cost of service to reflect advertisements and ad-related expenses that (1) did not benefit customers, (2) encouraged consumers to use natural gas products and services instead of electrical products and services, (3) were primarily image or informational ads, (4) subsidized unregulated entities, (5) fell outside of the test year, or (6) targeted KeySpan employees only.

By statute, the Company cannot recover from ratepayers any direct or indirect expenditure for promotional advertising. G.L. c. 164, §33A. The Department has clearly established that "gas companies must make an affirmative showing that the promotion of their utility services is in the best interest of the existing ratepayers before recovery of the associated costs will be allowed." *Boston Gas Company*, D.P.U. 93-60, p. 55, *citing Bay State Gas Company*, D.P.U. 92-111, at 201; *Bay State Gas Company*, D.P.U. 1122, at 33 (1982).

The Department evaluates advertising expenses in four categories: (1) image-related, (2) informational, (3) promotional, and (4) miscellaneous. *Boston Gas Company*, D.P.U. 96-50, (Phase I), pp. 63-65 (December 2, 1996), *citing Bay State Gas Company*, D.P.U. 92-111, pp. 182-191 (1992); *Boston Gas Company*, D.P.U. 93-60, p. 162 (1993); *Berkshire Gas Company*, D.P.U. 90-121, at 130-136 (1990). The Department further separated the promotional class into advertisements that (1) promote the use of gas explicitly in competition with unregulated fuel (oil), (2) do not explicitly target unregulated fuel, and (3) promote a company's non-utility operations. "Explicitly" means that the advertising "must leave the reader or listener with a reasonable impression that the target of the advertising is an unregulated fuel." *Id*. The Department excludes from recoverable costs of service give-away products or items designed to promote the company's image, advertisements that are not available for review, and promotional materials that target electricity end users. *Bay State Gas Company*, D.P.U. 92-111, pp. 184-185.

The "Value Snobs" radio advertisement is an example of an advertisement that the Company misclassified because it did not benefit ratepayers. Exh. AG-11. The Company never aired the advertisement and testified that "[ratepayers] don't receive any benefit for an advertisement that does not run." Tr. 14, p. 1807. The Department should remove the costs of the Value Snob advertisement ($92,663)[39] from the cost of service because the advertisement did not benefit ratepayers. The Department should also exclude from the cost of service $48,212 for advertisement invoices that the Company did not provide or were illegible.[40] Tr. 14, p. 1826; *Bay State Gas Company*, D.P.U. 92-111 at 185 (holding that advertisements for which the Company did not provide an advertisement copy were excluded from the cost of service).

The Company also failed to exclude certain miscellaneous expenses that did not provide a net benefit to ratepayers. For example, the Company included certain meal expenses where advertising leads were "discussed" (Tr. 14, p. 1818) and the cost of postage and letterhead for anticipated mailing projects, totaling $19,380.[41] Tr. 14, p. 1822. Data base mining and mailing list extractions ($18,191),[42] advertising agency commissions and monthly retainer fees ($93,396)[43] suffer the same defect. Exh. AG-15; Exh. AG-26.

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[39] This is a deduction for 25% of Exh. AG 25-1 (advertising expenses) Invoice Locator Numbers (4), (5), (6).

[40] Exh. AG 20-1(3), (13), (19), (20), (21), (27), (31), (36), (41), (42), (58), (62); and Exh. AG 25-1 (53), (61), (74), (129), (130), and (137).

[41] Exh. AG 20-1(5), (16), (17), (22), (28), (30), (44), (51), (54), (55), and (59); Exh. AG 25-1(8).

[42] Exh. AG 20-1(7), (8), (9), (10), (11), (14), (23), (24), (25), (33), (34), (38), (39), (43), (46), (48), (49), (50), and (53); Exh. AG 25-1(51) and (79).

[43] Exh. AG 20-1(4), (12), (26), (37).

The Department should also remove from the cost of service the costs of all advertisements that encourage consumers to use natural gas, not electric, services and appliances such as water heaters, air conditioners, pool/spa heaters, stoves, fireplaces, and patio lights ($230,151).[44] Exh. AG-2; Exh. AG-6; Exh. AG-11. The Department does not permit rate recovery for ads which encourage ratepayers to use one Department-regulated industry instead of another. *Berkshire Gas Company*, D.P.U. 90-121, pp. 133-134 (1990).

The Department denies recovery of costs associated with image advertising and/or general public relations that seek to cultivate a favorable image of the utility in the eyes of its ratepayers. *Bay State Gas Company*, D.P.U. 92-111 at 184; *citing Berkshire Gas Company*, D.P.U. 90-121, p. 131. In its filing, the Company seeks to pass along to ratepayers advertisement expenses related to informing customers about its charitable donations, historic renovation projects, business cards, and other community development that the Company should have classified as image, informational, and miscellaneous ad expenses. Exh. AG-25. The Department should exclude these costs ($173,164)[45] because the Company has not demonstrated that these advertisements give a direct benefit to Massachusetts customers.

KeySpan Home Energy Services, Gallineli Plumbing, and other plumbers get up to 50% of their advertisement costs paid as part of the VPI installer trade ally program, and the Company

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[44] The cost of these invoices is shown on Exh. AG-26 and Exh. AG 20-1(1), (6), (15), (18), (29), (35), (40), (45), (52), (56), (60); and Exh. AG 25-1(17), (20), (33), (34), (35), (44), (46), (48), (50), (56), (60), (62), (65), (67), (80), (88), (99), (114), (115), (124), (132), (134), and (136) ($134,770), together with the costs of the Rubber Duckie/Aquazoid ad ($95,381) (1/4 of Exh. AG 25-1(4),(5), and (6) + Exh. AG 25-1(29)) for a total of $230,151. The Rubber Duckie/Aquazoid advertisement encourages consumers to use natural gas services and appliances "in the kitchen, in the fireplace and yes, even in the bathroom." Exh. AG-11; cf. Exh. AG-39, Exh. AG-40, Exh. AG-2, Tr. 14, p. 1808.

[45] Exh. AG 25-1(18), (63), (78), (102), (111), (112), (131).

included these costs in the cost of service. The Department should reject this ratepayer subsidization of unregulated entities (third party contractors) and affiliates' advertisement expense ($18,917)[46] because the Company has not shown a direct benefit to ratepayers in this subsidy.

The Department should also exclude $2,300[47] of 2001 advertising expense incurred outside of the test year and $3,300[48] for advertisements to its own employees about employee benefits. *Boston Gas Company*, D.P.U. 93-60, p. 57 (holding that $74,200 in pre-test year rebates should be excluded because the Department did not find evidence to support the Company's decision to defer the cost of those rebates).

For these reasons, the Department should remove an additional $670,000 from the Company's advertising expense.

7. THE DEPARTMENT SHOULD CORRECT THE COMPANY'S BAD DEBT EXPENSE.

The Company testified that its net bad debt write-offs for 2002 were $15,572,000; its three-year weighted net write-off average was 1.83%; its allowable bad debt expense was $11,204,000; its 2002 test year bad debt expense was $15,503,342; and its total bad debt expense adjustment was $4,299,361. Exh. KEDNE/PJM-2, Revision 2, page 22 of 41; Tr. 8, pp. 959, 961. The Department should revise the Company's 2002 net write offs and the total bad debt

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46 Exh. AG 25-1(31), (54), (55), (89-92), and (108-110); Exh. AG 1-73(a); Tr. 17, pp. 2267-2269.

47 Exh. AG 25-1 (unnumbered - Boston Soc. of Architects) and (136).

48 Exh. AG 25-1(28), (59), (96), and (105).

expense adjustment (Exh. KEDNE/PJM-2, Revision 2, page 22 of 41, lines 13 and 14) because the test year amount is not representative.

First, the Company failed to include accurate recovery amounts for five months in the test year (July - September, November and December). Exh. KEDNE/PJM-2, Supp., p. 119. The Company claimed that it did not record write-off recoveries for the months of July-September 2002 because of the Company's conversion to CRIS, the new customer information system, on June 30, 2002. Tr. 8, p. 965-966; RR AG-36. The Company further claimed that these figures are net write-offs because the Company could not separate recoveries from writeoffs because of the CRIS conversion. Tr. 8, pp. 965-967; RR-AG-36.

There is no record evidence that would support the Company's assertion that net write-offs rose after reflecting recoveries for the third and fourth quarters of 2002 over the previous two quarters. It is equally plausible that the Company simply could not or did not track recoveries in the later months as it implemented the new CRIS software. Exh. KEDNE/PJM-2, Supp., p. 119. This, in turn, inflated the three-year weighted average of net writeoffs, inflated the allowable bad debt expenses, and reduced the total bed debt expense adjustment (Exh. KEDNE/PJM-2 Supp. p. 115, lines 6, 12, and 14; Tr. 8, p. 961-964). The Company, consequently, under-reported the bad debt adjustment to test year residual O&M expense base, which exaggerated the residual O&M expenses subject to inflation and the total inflation adjustment (Exh. KEDNE/PJM-2, Revision 2, page 28 of 41, lines 17, 23, and 26).

The Company also stated that it was able to track recoveries beginning in October 2002. RR-AG-36. The bad debt recoveries for November and December, $10.00 and $1.60 respectively, however, are abnormally low and the Company had no explanation for these amounts. Exh. KEDNE PJM-2 Supp., p. 119. The record shows that, using the two prior years of bad debt information, the Company's average monthly debt recovery was $183,781. *Id*. By not recording any recoveries for July - September and recording only $11.60 in recoveries combined for the months of November and December 2002, the Company under-reported the average amount of recoveries the Company would have recorded but for the CRIS conversion.

The Company chose to implement CRIS, the new customer information system, and to change its write-off policy voluntarily, but failed to average in the write-off recoveries that it did not record because of the CRIS conversion process. Tr. 8, p. 969. Ratepayers should not be penalized for the Company's choice of software. By omitting recoveries for five months of the test year, the Company created an unrepresentative level of uncollectible expense in the cost of service, contrary to Department precedent. *Fitchburg Gas and Electric Company*, D.T.E. 02-24/25, pp. 162, 169, 170 (2002); *Berkshire Gas Company*, D.T.E. 01-56 (2002), p. 92; D.T.E. 98-51, at 49; *Boston Gas Company*, D.P.U. 96-50 (Phase I), p. 70-71; D.P.U. 89-114/90-331/91-80, Phase I, pp. 137-140; *Commonwealth Gas Company*, D.P.U. 87-122, at 83 (1987). Furthermore, the Company has not provided any justification for this unrepresentative level of net write-offs.

The Department should direct the Company to produce a more representative level of net writeoffs and uncollectible expense by substituting the stable average of the prior two years' net writeoffs. To calculate this more representative level, the Department should average the 2000 and 2001 recoveries, replace the 2002 net write-offs amount with that average, and recalculate the resulting bad debt expense adjustment. Using this formula, the Department should increase the total bad debt expense adjustment by $183,671[49] and reduce the uncollectible amount in the proposed rate increase using the revised weighted average percentage. Exh. KEDNE PJM-2, Revision 2, page 4 of 41, line 12.

8. THE DEPARTMENT SHOULD REFLECT AN ADDITIONAL AMOUNT FOR DIG-SAFE FINES.

The Company adjusted its operating expenses for $71,150 in fines and penalties paid during the test year. Exh KEDNE/PJM-2 Supp. p. 132-135; Tr. 17, p. 2205. This amount includes $14,000 of $20,000 that KeySpan Service Company allocated to the Company, using the Company's 68.1% G03 allocation formula, for violations the Company paid to the Department and to New Hampshire.[50] Exh. KEDNE/PJM-2 Supp., p. 135; Tr. 17, p. 2212.

The Company agreed that any fines paid in the test year should be included in the Company's adjustment for fines and penalties. Tr. 17, p. 2210. The Company, however, failed to disclose an additional $51,000 in natural gas pipeline (dig-safe) violations that the Company paid the Department's Pipeline Engineering and Safety Division during the test year.[51]

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[49] The average of the two prior years' recoveries ($2,221,629.69 and $2,189,177.91) is $2,205,373.80. Exh. KEDNE/PJM-2 Supp., p. 119. The total averaged write-offs for 2002 becomes $15,055,155.19, the three-year total of write-offs is $37,334,155, the three-year weighted average of net write-offs is 1.80%, the allowable bad debt expense is $11,020,309, and the total bad debt expense adjustment is ($4,483,032) (Exh. KEDNE/PJM-2 Supp., p. 115, lines 3, 4, 6, 12, and 14), for a net increase in the bad debt expense adjustment of $183,671 ($4,483,032 - $4,299,361).

[50] The Company paid $17,000 to the Department and $3,400 to the State of New Hampshire in 2002. Exh. KEDNE/PJM-2 Supp., p. 135.

[51] These fines appear to be in addition to those the Company lists in its filing because none of the payment dates match. Compare Exh. KEDNE/PJM-2 Supp., p. 135 and August 12, 2003 letter from Robert Smallcomb, Director Pipeline Engineering and Safety Division, to the Attorney General. (The Attorney General asks the Department to incorporate by reference this August 12 letter under 220 C.M.R. 1.10(3) as the information is contained within its own records and is readily accessible to the parties.)

The Company acknowledged that its recording of dig-safe penalties reflects "sloppy accounting." Tr. 24, pp. 3346-3347. The Company paid these fines during the test year and they are readily ascertainable, Massachusetts-specific, and Company-specific dig-safe violations. The Department should reject the 68.1% presumptive allocation for dig-safe penalties and assign to the Company 100% of its natural gas pipeline (dig-safe) payments to the Department (totaling $68,000) as a matter of public policy. *Boston Gas Company*, D.P.U. 96-50 (Phase I), p. 110 (December 2, 1996); D.P.U. 88-67, Phase I, p. 43 (1988); *Kings Grant Water Company*, D.P.U. 87-228, pp. 18-19 (1988); *Nantucket Electric Company*, D.P.U. 1530, p. 26 (1983). The Department also should require the Company to set up separate dig-safe accounts in the future to correct this accounting problem.

9. THE DEPARTMENT SHOULD REVISE THE GAIN ON SALE OF THE CONCORD PROPERTY TO REFLECT THE COMPANY'S ENTIRE GAIN.

In 1998, the Company sold a tract of land in Concord, Massachusetts for $1.5 million. Tr. 17, p. 2234-2235; Exh. AG 6-41, p. 4. The Company reduced its cost of service by $40,000 to recognize a five-year amortization of net gain based on the book value of land, a 16.60% allocation of proceeds to utility property, and sale proceeds of $1,437,000. Exh. KEDNE/PJM-2, Revision 2, p. 15 of 41. The Company violated the Department's long-standing policy on gains of sale of utility property by not reflecting the entire gain on the sale of the Concord property in two respects. *Boston Gas Company*, D.P.U. 96-50 (Phase I), p. 111 (December 2, 1996).

First, the Company used the claimed sales proceeds of $1,436,570, not the purchase price ($1,500,000), as the starting point for its calculations. When asked to reconcile the sales price and sales proceeds, the witness could not explain the $63,430 difference. Tr. 17, p. 2235. The record does not provide that explanation, though the reasons for the difference are immaterial, since the appropriate starting point is the contract purchase price. Second, the Company understated the entire gain by applying the 16.6% utility/non-utility allocation before subtracting the book value of land ($9,950). Exh. KEDNE/PJM-2, Revision 2, p. 15 of 41. The Company admitted that an equally appropriate and more accurate method of calculating the gain on sale is to apply the allocation factor **after** subtracting the book value of land. Tr. 24, p. 3328. The Department should incorporate these two changes to reflect an additional amortized gain on the sale of the Concord property of $3,766.[52] *Boston Gas Company*, D.P.U. 96-50 (Phase I) (December 2, 1996), p. 111; *Massachusetts-American Water Company*, D.P.U. 95-118, pp. 142, 144 (1996).

10. THE DEPARTMENT SHOULD REJECT THE COMPANY'S PROPOSED RESEARCH AND DEVELOPMENT SURCHARGE BECAUSE IT IS UNNECESSARY, UNFAIR AND PREMATURE.

The Company seeks approval to charge its customers approximately $1.4 million per year by increasing the Local Distribution Adjustment Charge ("LDAC"). Exh. KEDNE/JFB-1, p. 54. The proceeds from this LDAC increase purportedly would fund research and development ("R&D") for the gas industry, performed by the Gas Technology Institute ("GTI") and others. Previously, a FERC-imposed interstate pipeline charge to LDCs, typically passed on to end-use customers, supported gas industry R&D. In 1998, FERC, the interstate pipelines and the LDCs

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[52] The gain should be calculated as follows: ($1,500,000 - 156,870 [net book value of building and equipment]- 9,950[book value of land]) x 16.6% = $221,308 ÷ 5 years = $44,262 - $40,496 [Company adjustment]= $3,766 additional gain.

agreed to phase out this mandatory FERC-approved surcharge over a period of five years. The charge is scheduled to end no later than December, 2004, with a true-up in 2005. *See* Exh. AG-27-1.

The Department should reject the proposed LDAC increase because (1) it is unnecessary--almost all of the R&D projects will proceed whether or not they are partially funded by Boston Gas customers; (2) it is unfair -- the proposed charge would force Boston Gas distribution customers to subsidize R&D that would primarily benefit other competitive businesses who do not pay a charge; and (3) it is premature and would lead to double collection in the rate year.

The Company presented Ronald Edelstein of GTI in support of R&D funding. Mr. Edelstein implied that R&D projects will not be funded unless its distribution ratepayers are charged the same level of R&D funding previously collected under the FERC-approved surcharge mechanism. Tr. 9, p. 1088. Mr. Edelstein could list only two projects, however, that might not proceed without funding from Boston Gas customers. Tr. 9, pp. 1033-1034. These two projects account for only approximately three to five million dollars, or 5-8%, of GTI's anticipated sixty million dollar budget for 2004. Tr. 9, p. 1036. With the possible exception of those two projects, Boston Gas customers could receive the same R&D benefits whether or not they are charged for R&D projects and whether or not KeySpan actually provides funding for GTI. Tr. 9, pp. 1033-34.

There is no persuasive evidence in the record that Boston Gas customers will receive benefits from R&D if this charge is collected, much less a benefit level proportional to the amount of the charge. Boston Gas distribution customers should not be forced to subsidize non-distribution R&D research. There are several categories of GTI's R&D that will have little or no direct benefit to Boston Gas distribution customers, and will instead primarily benefit others who will not be paying a charge. For example, the benefits of exploration and production R&D, pipeline R&D, power generation R&D, appliance and other end-use R&D and transportation R&D would flow primarily to exploration and production companies, the pipeline companies, the appliance sellers, and the transportation companies. KeySpan's various unregulated subsidiaries may benefit from these R&D projects, but pay no charge. Key Span shareholders would also benefit from R&D that leads to lower costs for natural gas or natural gas services, greater consumption of gas and greater revenues for the Company. Tr. 9, p. 1094. Since the shareholders would receive this economic benefit from such R&D research, they should fund the R&D projects. Instead, the Company is asking the Department to allow its shareholders and other entities to benefit at the expense of the Boston Gas customers.[53]

Mr. Edelstein of GTI also testified for the Company that the FERC-approved charge may continue to be collected throughout 2004, with a final reconciliation in 2005. Tr. 9, p. 1037. The Company proposes to collect its R&D LDAC increase beginning in January, 2004. Exh. KEDNE/JFB-1, p. 54. The Department should also reject the proposed LDAC increase because it would be premature and would result in a double collection of R&D funds from Boston Gas customers during the rate year.

[53] The real value of this service is underscored by the fact that KeySpan, as a whole, did not make any voluntary contribution during the test year without the order of a jurisdictional rate regulatory commission. RR-AG-40.

11. **THE DEPARTMENT SHOULD DISALLOW RECOVERY OF THE PROPOSED NON-UNION WAGE INCREASE BECAUSE IT IS UNREASONABLE IN LIGHT OF CURRENT WAGE LEVELS AND IS SUPPORTED BY FLAWED COMPARISONS.**

The Company proposes to increase its O&M expense by $1,409,000 for a non-union employees' general wage increase. Exh. KEDNE/PJM-1, p. 9; KEDNE/PJM-2, p. 7. The proposed non-union wage adjustment arises from direct and allocated pay increases taking effect between the test year and the midpoint of the rate year. Exh. KEDNE/PJM-1, pp. 7, 9; KEDNE/PJM-2, p. 7. The Department should disallow recovery of the Company's proposed non-union wage increase because the increase is unreasonable in light of the Company's already relatively high non-union wage levels.

The Department has allowed increases for non-union salaries and wages when the increases are reasonable and in line with the salaries and wages of similar utility employees of other companies. *See Berkshire Gas Company*, D.T.E. 01-56, p. 54 (2002); *Blackstone Gas Company*, D.T.E. 01-50, p. 9 (2001); *Boston Gas Company*, D.P.U. 96-50 (Phase I), p. 42 (1996). To meet this standard, a company must demonstrate (1) an express commitment by management to grant the increase, (2) an historical correlation between union and non-union raises, and (3) that the amount of the non-union increase is reasonable. *Fitchburg Gas and Electric Light Company,* D.T.E. 02-24/25, pp. 89-90 (2002); *Massachusetts Electric Company*, D.P.U. 95-40, p. 21 (1995); *see also Berkshire Gas Company*, D.T.E. 01-56 at 54; *Blackstone Gas Company*, D.T.E. 01-50 at 9; *Boston Gas Company*, 96-50 (Phase I) at 42. In determining the reasonableness of a proposed wage increase, the Department looks at the overall compensation package and not just the wage component. *Massachusetts Electric Company*, D.P.U. 95-40 at 26; *Fitchburg Gas and Electric Light Company,* D.T.E. 02-24/25 at 90.

The Company has failed to meet the reasonableness prong of the standard. The Company has provided a comparison, the accuracy of which is disputed, of the average total compensation per employee among the various utility companies in New England. Exh. KEDNE/JCO-12. The Company's figures indicate that the Company's average total compensation per employee is greater than that of other New England gas company employees. Specifically, the Company's employees already earn an average total compensation (total salaries, wages and benefits) of $82,729 per employee, 6.3% more than employees at other New England gas companies, who earn an average total compensation of $77,811 per employee. Exh. KEDNE/JCO-12; Tr. 16, pp. 2133-2137. The Company's average total compensation per employee is above the median level among the nine New England gas companies. Exh. KEDNE/JCO-12. Allowing the Company's proposed non-union wage increase would drive the Company's non-union compensation further above and out of line with the salaries and wages of similar employees of other New England gas companies. In light of these facts, the Department should reject as unreasonable the Company's proposed non-union wage increase.

The Department also should reject the Company's proposed non-union wage increase because the Company's methodology is flawed and there are miscalculations in its comparative analysis of employee compensation. The Department requires utilities to provide a comparative analysis of their employee compensation expenses to allow the Department to make an informed decision on the reasonableness of those expenses. *See Fitchburg Gas and Electric Light Company,* D.T.E. 02-24/25 at 90-91; *Boston Gas Company*, D.P.U. 96-50 (Phase I) at 47. The

Company's flaws and miscalculations hinder the Department's ability to assess the reasonableness of the Company's proposed increase. For example, the Company admits that it erred in its Exhibit KEDNE/JCO-7 by mislabeling various median hourly rates as average hourly rates and by erroneously comparing average wage figures to median wage figures. Tr. 16, pp. 2084-2088, 2092-2096. This error is significant, renders the comparison analysis on that particular exhibit useless, and casts doubt on the accuracy of the remainder of the Company's employee compensation analyses. Indeed, as a result of this error, the Company failed to provide the proper figures needed to perform any meaningful comparison of hourly wages among the Northeast or New England utility companies. *See* Tr. 16, pp. 2092-2096 (averages calculated); *see also* Tr.16, pp. 2137-2139 (survey pages missing which support Exhibit KEDNE/JCO-9 and related non-union data).

The Company's methodology is also flawed because the Company cast an overly broad net among the New England utility companies in its comparison, which resulted in an inflated average total compensation per employee figure for comparison purposes. Exh. KEDNE/JCO-12. Boston Gas Company did not limit itself to gas companies like itself, but included electric companies as well. Including electric companies inflated the average total compensation per employee to $96,285, versus $77,811 for gas companies alone. This correction in the Company's methodology raises the Company from below the average to above the average. For these reasons, the Department should reject the proposed non-union increase.

a. The Company Should Disallow Recovery Of All Or Part Of The Proposed Incentive Increase For Non-Union Employees.

The Company proposes to increase its O&M expense by $2,539,000 for an incentive increase to both union and non-union employees. Exh. KEDNE/PJM-1, pp. 9-13; KEDNE/PJM-2, pp. 8-9. The Company's Incentive Plan is structured to provide both performance and financial goals or incentives.[54] Exh. KEDNE/JCO-1, pp. 9-11. The Company capped all union incentive increases at $750 per employee, while the non-union incentive increases ranged from a low of approximately $2,000 to a high of approximately $22,000 during the test year. Exh. AG-6-21, Attachment. The Department should disallow recovery of all or part of the proposed non-union incentive increase because the proposed increase is unreasonable and the Company has not shown that it provides any benefit to customers.

The Department has generally allowed incentive compensation expenses and proposed increases to be included in a utility company's cost of service provided those expenses and proposed increases are (1) reasonable in amount, and (2) reasonably designed to encourage good employee performance. *Fitchburg Gas and Electric Light Company,* D.T.E. 02-24/25 at 99. *Boston Gas Company*, D.P.U. 93-60, pp. 98-99 (1994). A company's incentive compensation plan must have defined goals and quantifiable benchmarks that benefit customers. *Boston Gas Company*, D.P.U. 93-60 at 98-99; *Bay State Gas Company*, D.P.U. 92-111, p. 115 (1992); *Fitchburg Gas and Electric Light Company,* D.T.E. 02-24/25 at 99-100.

[54] According to the Company, its general categories of goals include (1) corporate goals, (2) business unit or area specific goals, and (3) strategic initiative or assessment goals. Its area specific goals include (1) achieving earnings objectives, (2) containing operations and maintenance costs, (3) ensuring customer satisfaction, (4) maintaining or improving safety, and (5) developing workforce diversity.

As noted above, the Company's average total compensation per employee is above the median level for the other New England gas companies. Any additional increase in non-union employee compensation—be it incentive or otherwise—is unnecessary and inappropriate when customer bills have risen substantially over the past year and are forecast to remain at high levels. Also, certain of the proposed incentive increases are unreasonable in amount, ranging as high as approximately $22,000 for some employees in the test year. Exh. AG-6-21, Attachment. Indeed, based upon the design of the Incentive Plan and the weight assigned to various goals, non-union employee increases could total well above the test-year high of approximately $22,000. *See* Exh. AG-10-32, Attachment; AG-10-33, Attachment. Additionally, some of the goals upon which non-union performance is evaluated are unreasonable because they are too subjective and/or the weight attributed is disproportional. *See* Exh. DTE-2-16, Attachment.[55] Finally, the Company has not shown that several of the performance incentive goals such as supporting high visibility groups and additional press coverage provide any benefit to customers.

For these reasons, the Department should disallow recovery of the Company's entire proposed non-union incentive increase or, at a minimum, disallow the payroll adjustment portion of the proposed increase attributable to the subjective goals, disproportionately weighted goals, and goals that provide no benefit to customers.

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[55] The company lists as goals (1) "Ability to Get the Job Done"; (2) "$ Value of DTE Adjustments"; (3) "Lobbying ..." (4) "Media Relations..." for more press coverage; and (5) "Capital Market" financing goals.

b. The Company Does Not Need Non-Union Merit, Incentive or Other Compensation Increases Because its Employee Benefit Compensation Is Already Ample.

The Company provides generous and substantial benefits to its non-union employees. The Company's uncapitalized ratio of total benefits to total compensation is approximately 26%. *See* Tr 16, pp. 2132-2133; Exh. AG-1-40. The benefits that the Company provides to its employees, in addition to health and dental benefits, include the (1) Scholarship Award Program, (2) Tuition Reimbursement Program, (3) Health Club Program, (4) Service Recognition Program, (5) Shoe Allowance, (6) Meal Allowance, (7) Sunday Bonus Program, (8) Corporate Sponsored Membership, (9) Improved Meter Reader Incentive Plan (10) Shift Differential Program, (11) Stock Purchase Plan, (12) Free Heating Equipment, (13) 0% Heating Equipment Financing, and (14) Employee Rebate Program. Exh. PJM-2, p. 26; PJM-2, Supplemental, pp. 21, 24, 28; Exh. AG-5; RR-DTE-1; Tr. 17, pp. 2238-2241; Tr. 16, pp. 2108-2121. The Department, in examining the reasonableness of any proposed wage or salary increase, has looked at the overall compensation package, recognizing that different components of employee compensation (wages versus benefits) are to some extent substitutes for each other. *Fitchburg Gas and Electric Light Company,* D.T.E. 02-24/25 at 90. Because the Company rewards its employees with a very generous benefits package, there is no need for, and it would be inappropriate to charge customers for, non-union merit or incentive increases. The Department, therefore, should deny the proposed non-union merit, incentive, or other wage or salary increase.

12. THE DEPARTMENT SHOULD REMOVE EXTRA CASH BONUSES FROM THE COST OF SERVICE.

The Department should remove from the pro forma cost of service the extra cash bonuses that the Company paid to employees during the test year. These costs (1) duplicate incentives in the existing program for which the employees are already compensated, and (2) are non-recurring, non-extraordinary expenses.[56]

The Company claims that incentive pay is an important part of its overall plan to provide economic service. It has one comprehensive plan that provides employees extra pay for meeting and surpassing certain goals during any given year. Exh. KEDNE/JCO-1, p. 8. The Company has been increasing the incentive proportion of total pay that its employees receive. Exh. KEDNE/PJM-2, pp. 8-9. During the test year, the Company made special cash bonus payments to employees in addition to the incentive pay that they already receive. Tr. 25, pp. 3502-3506; RR-AG-100.

The Department considers three classes of expenses recoverable through rates (a) annually recurring expenses are eligible for full inclusion in cost of service unless the record supports a finding that the level of the expense in the test year is abnormal, (b) periodically recurring expenses are normalized so that the cost of service will include only the appropriate portion of the expense, and (c) non-recurring expenses that are so extraordinary in nature and amount as to warrant their collection are amortized over an appropriate period. *Fitchburg Gas and Electric Light Company*, D.P.U. 1270-1414, pp. 32-33 (1983). The Company's special cash bonus payments do not meet any of these criteria for inclusion in the cost of service.

[56] KeySpan provides base pay and incentive pay for all of its employees. Tr. 5, p. 542.

The special cash bonus payments are made to employees on a one time basis as incentives for performance. Exh. RR-AG-100. The total amount of the payments made during the test year was $90,494. *Id*. ($81,052 allocated from the Service Company, and $9,442 directly incurred by Boston Gas). Since these payments are non-recurring and non-extraordinary in amount, they should be removed from the cost of service. The payment of these special cash bonuses duplicates the incentives and the associated incentive pay that employees receive under the existing incentive program. Customers should not be charged twice for these incentives. The Department should reduce the cost of service by $90,494 to remove the Company's extra incentive cash bonus payments made to employees.

13. THE DEPARTMENT SHOULD CORRECT THE LEVEL OF CAPITALIZED EMPLOYEE BENEFITS.

Boston Gas failed to capitalize an appropriate level of its employee benefit costs during the test year in this case. The Company capitalizes the costs that it incurs to put its utility plant into service. Exh. AG-1-40. This includes not only the materials cost, but also the overhead and labor costs. The labor costs that are capitalized include both the salaries and wages and the benefits paid out as compensation to the Company's employees. *Id*. The Company capitalized 28.64 percent of its wages and salaries during the test year, but only 18.45 percent of its benefits. *Id*. The Company, before the test year in this case, had historically capitalized benefits at an average rate of 94 percent of the rate of capitalization of wages and salaries. *Id*. During the test year, however, the Company capitalized benefits at a rate of only 64 percent of the rate of salaries and wages. [0.64 = 18.45 / 28.64]. This undercapitalization of employee benefits means that the Company has overstated its operations and maintenance expenses included in the test year cost of service.

The total employee benefits cost incurred during the test year was $33,202,006. *Id.* At the 18.45 percent capitalization rate, the Company capitalized only $6,124,222 of that cost. *Id.* If the Company had capitalized benefits at the same 28.64 percent rate as salaries and wages, the Company would have capitalized $9,509,055 of benefits ($33,202,006 x 0.2864), $3,384,833 more than was recorded in the test year. *Id.* [$3,384,833 = $9,509,055 – $6,124,222] The Department should reduce the Company's cost of service by $3,384,833 to bring the benefits capitalization in line with the salaries and wages capitalization.

The Company also failed to capitalize any portion of the Incentive Compensation adjustment that it proposes. Exh. KEDNE/PJM-2, p. 8. The Company used the total cost amount for the test year as well as the pro forma amount that it proposes to include in rates. Exh. KEDNE/PJM-2, p. 8-9; Tr. 5, p. 540-541. As a result, the adjustment that the Company proposes is the total adjustment for total cost, the expense portion as well as the capitalized portion. To rectify this problem, to the extent that the Department allows any incentive compensation, all determinants should be multiplied by 66.30 percent to calculate the expense-only portion. Exh. KEDNE/PJM-2, p. 9.

14. THE DEPARTMENT SHOULD REMOVE THE SHAREHOLDERS SERVICES EXPENSE FROM THE TEST YEAR COST OF SERVICE.

The Department has consistently excluded shareholders services expenses from the cost of service. *New England Telephone and Telegraph Company d/b/a NYNEX*, D.P.U. 94-50, pp.

326-327 (1995); *Berkshire Gas Company*, D.P.U. 92-210, p. 52 (1993); *Western Massachusetts Electric Company*, D.P.U. 88-250, p. 47 (1989). The Company has not provided any reason for the Department to deviate from this precedent. The Department should remove the test year amount of shareholders expenses, reducing the cost of service by $114,000. Exh. AG-1-76.

15. RATE CASE EXPENSE.

a. Legal Services

Companies are under an affirmative duty to contain rate case expenses. *Fitchburg Gas And Electric Light Company*, D.T.E. 98-51, p. 57 (1998). In the Company's last case, D.P.U. 96-50, the Department put Massachusetts utilities on notice that outside legal and consulting services must be subject to a competitive bidding process or an adequate justification must be provided for the failure to issue a request for proposal ("RFP"). *Boston Gas Company*, D.P.U. 96-50, p. 79 (1996). Invoices for services provided to the utility should contain sufficient detail to describe the nature of the work. *Fitchburg Gas And Electric Light Company*, D.T.E. 98-51, p. 61. Vague or general descriptions are simply insufficient. *Id*. Failure of a company to adhere to any of these requirements may result in disallowance of the requested rate case expense. *Id*. pp. 56-61.

The rate case expense is then normalized over the period of the PBR, if any. *Berkshire Gas Company*, D.T.E. 01-56, p. 74 (2002). In the absence of a PBR, "the Department determines the appropriate period for the recovery of rate case expenses by taking the average of the intervals between the filing dates of a company's last four rate cases (including the present case) rounded to the nearest whole number." *Fitchburg Gas And Electric Light Company*, D.T.E. 98-51, p. 54.

According to the 2002 engagement letter for legal services in connection with this rate case, the Company's outside law firm promised to provide Boston Gas with a twenty percent "discount from [the firm's] current billing rate." Exh. AG 5-2; Tr. 25, pp. 3482-3488, 3499-3500 discussing Exh. AG 5-2. Comparing the hourly rate for the rate case with the hourly rate for the test year, however, reveals that the Company did not receive the promised twenty percent discount for this rate case. Compare Exh. AG-5-6 (Keegan, Werlin & Pabian rate case invoices) with Exh. AG-1-95 (supplemental)(Keegan, Werlin & Pabian test year legal expense invoices).[57] The hourly rates for counsel appearing at the rate case hearings was the same rate charged to the Company during the test year. There is no "discount" as originally promised in the engagement letter. Furthermore, the Company did not issue an RFP to solicit competitive bids for legal services in connection with the rate case. Exh. KEDNE/PJM-1, p. 24. The Company, then, has no objective no way to determine whether another law firm either would charge at lower hourly rates or could prepare and defend the Company proposal in fewer billable hours. Under the circumstances where a company, like Boston Gas, forgoes the RFP process based on the close working relationship between the outside law firm and the utility, any offered discount for the rate case work should be taken very seriously. The Department should apply the promised discount and reduce the total hourly rate charged for legal services by twenty percent. In the alternative, the Department should reject the legal fee expense for failure to issue an RFP.

[57] Although the actual hourly rate has been redacted from invoices, these rates can be calculated by simply dividing the hours worked by the total charge for a specific lawyer on any given day.

The Company's 2003 rate case expense for legal fees also includes invoices from 2002 for work performed for the Company for an abandoned rate case based on a 2001 test year. Tr. 12, pp. 1540-1544; Exh. AG-21 (May 21, 2002 Letter to Department from Joseph F. Bodanza). According to Mr. Bodanza, the Company, at the end of 2001, had identified a "substantial revenue deficiency" using a 2001 test year and had planned to file a rate case by May 15, 2002. Exh. AG-21, p. 1. The Company delayed filing this rate case in favor of exploring rate consolidation, ultimately an unsuccessful endeavor. Tr. 12, pp. 1540-1544; Exh. AG-21. According to the "Re: 2001 Rate Case" notation on the invoices, legal work performed on that rate case ended in August, 2002, and totaled $45,350.00. Exh. AG-5-6 (August 22, 2003 supplement, pp. 76-88). The Department should not allow fees for an abandoned rate case project based on a different test year as a recoverable expense.

The Company must not be permitted to recover legal fees through the Local Distribution Adjustment Clause ("LDAC") associated with the law firm Dickstein, Shapiro, Morin and Oshinsky for work related to environmental remediation. RR-AG-95; *MGP Remediation*, D.P.U. 89-161 (1990). Mr. Fredrick Lowther is a director of the KeySpan Energy Development Corporation and also a law partner at Dickstein, Shapiro, Morin and Oshinsky. Exh. AG-1-93; Exh. AG-1-95; Exh. AG-1-98 (mapping all the KeySpan companies). However, the record evidence shows that the Company did not send out these services for competitive bidding, but instead awarded the business to a KeySpan insider. Exh. AG-1-95. The Department should exclude the recovery of these legal fees. Exh. AG 1-95 (spread sheet).

b. Consulting

The Department requires Massachusetts utilities to subject outside rate case consulting services to a competitive bidding process or provide an adequate justification for the failure to issue a request for proposal. *Boston Gas Company*, D.P.U. 96-50, p. 79. The Company did not issue an RFP to solicit competitive bids for any of the numerous rate case consultants used in connection with this case. Exh. KEDNE/PJM-1, p. 24, Exh AG-5-2, Exh AG-5-6 (original and multiple updates). The Company has no objective method to determine whether these services can be provided at lower costs, a particularly important check in this proceeding since the Company's PBR consultant, the Pacific Economic Group ("PEG") may charge nearly $1 million dollars for a price cap formula that would raise rates at a level greater than inflation. Exh AG-5-6. As a result, the expense associated with the outside rate case consultants should be rejected.

The Company caused the high costs by filing a case that contains material for at least three separate proceedings: a cost of service rate case, a PBR investigation involving complex studies and a merger review case. Had the Company submitted filings related to these three general topics in a reasonably coordinated manner (the merger occurred in 2000 and the previous PBR expired in 2001) consumers would not be faced with such a large rate case expense now. The Company already has a representative level of legal expense in rates to account for ongoing activities associated with utility operations. By filing these cases together, the Company increased rate case expense, rather than lessen it.

VI. COST OF CAPITAL

The cost of service includes a return on rate base that provides the investors of the Company a return on the net investment that they have made in the Company. Exh. KEDNE/PJM-2, p. 1. The return compensates the debt holders, preferred stockholders, and common stockholders. *Id.*, p. 36. The dollar amount of the return is determined by multiplying the dollar amount of rate base by the overall cost rate of these different costs of capital weighted by the amount of each outstanding. *Id.* The different components of the overall cost of capital will be analyzed below.

A. THE DEPARTMENT SHOULD REJECT THE COMPANY'S PROPOSED CAPITAL STRUCTURE AND ARTIFICIAL DEBT RATIO.

The Department should use a hypothetical capital structure in determining the Company's overall weighted cost of capital to protect ratepayers from an excessive rate of return on rate base. Because of Eastern Enterprise's merger with KeySpan, the push-down of an acquisition premium, and the $650 million of debt owed to KeySpan, the Company's capital structure and the resulting weighted cost of capital do not represent that of a cost efficient regulated gas distribution company. Specifically, the Company's debt ratio is too low and the cost of debt is too high.

The Department must protect Boston Gas Company's customers from excessive rates of return in reviewing and applying a proposed capital structure. *Blackstone Gas Company*, D.T.E. 01-50, p. 25 (2001); *Assabet Water Company*, D.P.U. 95-92, p. 33 (1996); *Wylde Wood Water Works*, D.P.U. 86-93, p. 25 (1987); and *Blackstone Gas Company*, D.P.U. 1135, p. 4 (1982).

The Department has found that “where a capital structure has been found to deviate substantially from sound and well established utility practice, the Department has imposed a hypothetical capital structure of 50 percent debt and 50 percent common equity for ratemaking purposes.” The Company’s proposal in this case does not comply with the Department’s precedent.

The Company’s debt ratio at the end of the test year in this case was 59.4 percent, which gave the Company a strong “A” rating from all of the bond ratings agencies. Exh. KEDNE/PRM-1, p. 18. This is approximately the same debt ratio and bond rating as KeySpan, the Company’s parent company. Exh. AG-1-16. Here, however, the Company proposes to “eliminate” the effects of the merger and push down adjustments, arriving at a 32.01 percent debt ratio. Exh. KEDNE/PJM-2, p. 36. Finding the debt ratio to be unreasonably low after these adjustments, the Company proposes a hypothetical capital structure that is only 48.16 percent debt. Exh. KEDNE/PJM-1, pp. 36-37. Furthermore, the Company assumed that the cost of the debt used to “make up” the incremental amount added in the artificial capital structure was only the same as the cost of the old debt that was issued back in 1995.

The Department should reject the Company’s proposal to reduce its debt ratio from 59.4 percent to 48.16 percent and replace it with an equity-heavy capital structure. The Company did not prove that its capital structure and the resulting capital ratios were out of line with market requirements. Although the Company’s book capital structure, before any adjustments, may have more debt than equity, it is not out of line with market expectations for an “A” rated company. Boston Gas and its parent KeySpan have 59 percent or greater debt ratios, and an “A” rating. Exh. AG-1-16.

The Company's attempt to "eliminate" all of the debt that was pushed down from KeySpan is inappropriate. The Company has not issued any long-term debt to the market in the last seven years, and does not expect to issue any to the market in the next five years, if ever. Exh. AG-1-13. Boston Gas has been, and likely will continue to be, financed by debt issued by KeySpan and then "pushed down" as accounts payable for which the parent can charge any "reasonable" rate under any term structure it decides. Clearly, the $650 million in debt issued to KeySpan did not result from merger requirements. The Department should include this debt owed to KeySpan as Boston Gas debt in determining the capital structure in this case. The Department should deny the Company's request to use a 48.14 percent debt ratio and instead use the Company's actual 59.40 percent debt ratio.

B. THE DEPARTMENT SHOULD USE ALL OF THE COMPANY'S OUTSTANDING DEBT TO DETERMINE THE COST RATE OF DEBT IN ITS CAPITAL STRUCTURE.

The Department should use all of the Company's outstanding debt to determine the cost rate of debt in its capital structure. The Company proposes to use the weighted cost of only its 1995 debt issues for all of the debt in its capital structure, even though it has other lower cost debt outstanding. Exh. KEDNE/PJM-2, p. 36. The Company's proposal fails to recognize the fact that it is financing the Company with other long-term debt. Failure to recognize this other debt means that shareholders will reap all of the benefits of the lower interest rates that have occurred since the issuance of the 1995 bond series. The Department should use the cost of the Company's debt issuance to KeySpan for all debt in the capital structure that it determines is appropriate over and above the $210 million amount issued in 1995.

C. THE DEPARTMENT SHOULD ADOPT A COST OF COMMON EQUITY OF 8.99% OVERALL, AND LOWER FOR RESIDENTIAL CUSTOMERS.

Unlike costs of debt and preferred stock, the cost of the Company's common equity is not readily measured. The Company sponsored the testimony of Mr. Paul Moul regarding the cost of common equity. Exh. KEDNE/PRM-1. Mr. Moul performed four analyses of the cost of equity: (1) a Discounted Cash Flow analysis ("DCF"), (2) a Risk Premium analysis, (3) a Capital Asset Pricing Model analysis ("CAPM"), and (4) a Comparable Earnings analysis. *Id.*, pp. 3-4. Since the Company does not issue common stock that is publicly held or traded, it is impossible to determine the market cost of equity for the Company's stock using any market based approach. *Id*. Therefore, Mr. Moul chose a group of companies that he deemed comparable in investment risk to Boston Gas Company and performed his cost of equity analyses on this group of companies to determine a cost of common equity for the Company. *Id*.

Mr. Moul's methodologies are fundamentally flawed and should be rejected by the Department. He has testified many times before this Department and The Department has rejected his analyses and recommendations rejected each time. *See e.g.*, *Berkshire Gas Company*, D.T.E. 01-56 (2001); *Boston Gas Company*, D.P.U. 96-50 (1996). While changing the companies that comprise his comparison group and updating the numbers, his analyses remain basically the same as those that the Department has repeatedly rejected. His cost of equity analyses here again grossly overstate the cost of capital for the barometer group and the Company. Appropriate corrections to his analyses result in a cost of common equity of 8.99

percent. The Department should use a cost of common equity no higher than 8.99 percent to determine the Company's revenue requirement in this case.

1. MR. MOUL'S ANALYSIS IS FUNDAMENTALLY FLAWED AND SHOULD BE REJECTED BY THE DEPARTMENT.

a. Discounted Cash Flow Analysis

Mr. Moul performed a DCF analysis on a group of companies that he deemed were comparable to the Company in investment risk. Exh. KEDNE/PRM-1, pp. 15-24. The economic theory underlying the application of the DCF analysis is that the market price that an investor is willing to pay for a share of common stock is equal to the present value of the cash dividends and the proceeds from the sale of the investment when the investor sells the stock. *Id*. Appendix E, p. 1. The DCF theory can be modeled by the following equation:

$$k = \frac{D}{P} + g$$

where k = the investors' required return on common equity

D = the dividend per share paid in the next period

P = the current market price per share of the common stock

g = the investors' mean expected long-run growth rate in dividends paid per share.

Id., Appendix E, pp. 1-2. Some of the components of the model, like the current price and the current dividend in effect during the period, are easily measured. The investors' expectations of the growth in dividends over the next year and over the rest of the investors' holding period, however, are not directly measurable. Each of these components to the model will be discussed below.

The dividend yield component of the DCF model is determined by dividing the indicated dividend by the current market price of the stock.[58] Exh. KEDNE/PRM-1, pp. 27-29. Using the dividend yield based on the information of one point in time will result in a volatile yield that will be susceptible to the peculiarities of "one day" events that might effect the market. *Id*. To avoid any abnormalities associated with using "one day" information, it is appropriate to use the average of several months of dividend yields. *Id*.

Mr. Moul provided the most recent twelve months of dividend yield information for this comparison group's common stock in his response to Exh. AG-RR-67. From this information, the most recent six month dividend yield average is 4.88 percent while the most recent three-month and twelve-month averages are 4.62 and 4.99 percent, respectively. *Id*. Based on these yields, a 4.88 percent dividend yield adjusted for the growth rate discussed below is an appropriate basis for the Department to use in its analysis of the DCF model.

The growth rate used in the DCF model is the investors' mean expected long run growth rate in dividends paid per share. Exh. KEDNE/PJM-1, Appendix E, p. E-9 ("viewed in its infinite form, the DCF model is represented by the discounted value of an endless stream of

[58] The indicated dividend is determined by annualizing the level of the current quarterly dividend per share being paid.

growing dividends"). Since it is impractical to measure all of the investors' expectations regarding their growth rate estimates, it is necessary to use proxies for those expectations. These proxies include historical and forecasted measures of dividends, earnings, and book value per share growth rates as well as the growth rates from retained earnings. *Id.*, pp. 28-29. Mr. Moul provided some of these proxies for the comparison group.

	Five-Year Historical	Ten-Year Historical	Five-Year Projected
Dividends Per Share	2.81%	2.63%	2.50%
Earnings Per Share	2.88	4.44	6.69[59]
Book Value Per Share	3.94	3.69	5.13

Exh. KEDNE/PRM-2, p. 10 and Exh. AG-14-20.

Mr. Moul has again proposed a DCF growth rate estimate without any basis, choosing the highest available estimates and ignoring historical data to determine his averages. The upward bias in his DCF growth rate estimate is obvious. His growth rate estimate for the comparison group of 6.00 percent is 319 basis points above the historical dividend growth rate and 350 basis points above the projected dividend growth rate. *Id.* His chosen methodology of basing the DCF growth rate estimate on short-term earnings projections has not stood the test of time. In the Company's last base rate case D.P.U. 96-50, Mr. Moul estimated that the growth rate for a similar comparison group would be 5.5 percent. In fact, the dividends, earnings and book value

[59] The earnings per share five-year forecast is the simple average of those statistics found on Exh. AG-14-20.

growth rates were all 4.44 percent and below over the last ten years.[60] *Compare Boston Gas Company,* D.P.U. 96-50 (Phase I), p. 117 (1996) and Exh. KEDNE/PRM-2, p. 10. Mr. Moul's short-run earnings growth rate estimate of 6 percent for his gas distribution companies is 50 basis points higher than the 5.5 percent long-run consensus growth rate forecast of the overall economy. Exh. AG-14-9, March 10, 2003, *Blue Chip Economic Indicators*, p. 14, ("Nominal G.D.P. Consensus" is 5.4% for 2005-2009 and 5.5% for 2010-2014) .

Clearly, Mr. Moul's estimates, based on the short-term earnings per share forecasts, are inflated, and should be rejected by the Department. Instead, the Department should base its DCF growth rate on more reasonable growth rate proxies that are consistent with historical measures as well as reasonable long-run forecast measures of growth. For instance, the Department should consider that the average of the five-year historical and forecasted growth rates in dividends per share yields a 2.66 percent growth rate. [(2.81% + 2.50) / 2]. Exh. RR-AG-10, [Exh. BG-12, p. 1, Schedule 8, Update.] Averaging the five-year historical and forecasted growth rates in earnings per share yields a 4.79 percent growth rate. [(2.88% + 6.69%) / 2]. *Id*. Averaging the five-year historical and forecasted growth rates in book value per share yields a 5.07 percent growth rate. [(4.94% + 5.13%) / 2]. *Id*. Given these averages, a 4.0 percent DCF growth rate would be a reasonable estimate of the DCF growth rate that investors expect.

The Department should reject Mr. Moul's proposed DCF analysis. Instead, an appropriate proxy for the current dividend yield based on the latest information available is 4.88 percent; an appropriate DCF growth rate is 4.0 percent. Using these parameters, a DCF cost of common equity can be determined:

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[60] These measures of growth occurred during one of the longest economic expansions in U.S. history.

	Growth Rate at 4.0%
Current Dividend Yield	4.88%
DCF Dividend Yield	4.98
Growth Rate	4.00
DCF Cost of Common Equity	8.99%

This DCF analysis provides a reasonable cost of equity estimate for Mr. Moul's comparison group.

b. Capital Asset Pricing Model Analysis

Mr. Moul performed a Capital Asset Pricing Model analysis to estimate the cost of equity for his comparison group. Exh. KEDNE/PRM-1, pp. 46-50 and Appendix H. The Department should reject Mr. Moul's CAPM analysis not only because he applied the model poorly, but also because the CAPM's underlying assumptions depart so substantially from the real world that the model cannot reliably determine the cost of common equity for a utility company.

The CAPM is a risk premium approach used to determine the cost of assets. *Id*. Like other risk premium approaches, it is based on the assumption that investors require a higher return on their investment for them to hold assets of greater risk. *Id*. The CAPM approach breaks the total risk of an asset into two components, systematic risk and unsystematic risk. *Id*., Appendix H, p. 1. Systematic risk represents the variability of the return on an investment associated with the effect of economy-wide forces (*e.g.* information and interest levels). *Id*.

Unsystematic risk, on the other hand, represents the risk associated with asset specific risks (*e.g.* risks that are specific to a particular company like industry competition and the quality of a company's management). *Id*. Portfolio theory assumes that an asset is evaluated in the context of a well-diversified portfolio where the unsystematic risks associated with individual assets cancel each other out. *Id*. Under the same theory, since unsystematic risk can be avoided with a well-diversified portfolio, the CAPM model should only focus on the amount of systematic risk associated with the asset. *Id*.

The CAPM measures the systematic risk of an asset with a factor known as beta. *Id*., pp. 2-3. The Model defines the beta value of all assets, on average, as equal to 1.0. *Id*. In the Model, an asset with a beta of 1.0 will have a return, which will have variations equal to the variability of the returns of the market as a whole. *Id*. The price of an asset with a beta of 1.0 will increase by 10 percent when the market value as a whole increases by 10 percent. *Id*. Conversely, the asset's price will decrease by 10 percent when the market value goes down by 10 percent. *Id*. Furthermore, the price of an asset with a beta of 1.5 will increase by 15 percent when the market increases 10 percent and decrease 15 percent when the market decreases 10 percent. *Id*. If the beta is 0.5, the asset's price will increase 5 percent when the market increase 10 percent, and it will decrease by 5 percent when the market decreases by 10 percent. *Id*.
The CAPM theory provides a formula to determine the return on the asset that is required by the market. *Id*. The formula is as follows:

r = rf + b x rp

where r = the market required return on the asset

rf = the return on risk-free investments

b = the beta of the asset

rp = the expected difference between the return on the market as a whole and the return on the risk-free asset.

Id. This is the formula that Mr. Moul used to perform his CAPM analysis in this case.

The CAPM theory and the formula derived from the theory are based on many assumptions. Although some of these underlying assumptions of the CAPM are true in the real world, several of them just do not hold true for the application of the Model in the case of an investment in the comparison group's common stock. Without these assumptions that are fundamental to the CAPM, the use of the Model is inappropriate, and must be rejected by the Department.

The Department has found that the assumptions underlying the CAPM are too "heroic" to make its application to a utility stock useful. *Boston Gas Company*, D.P.U. 96-50, p. 125 (1996); *Berkshire Gas Company*; D.P.U. 92-210, pp.148-150 (1993); *Boston Gas Company*, D.P.U. 92-78, p. 113 (1992); *Boston Gas Company*, 88-67 (Phase I), p. 184 (1988); *Commonwealth Electric Company*, D.P.U. 956, pp. 54-55 (1982). In *Commonwealth Electric Company*, the Department found that the following assumptions too unrealistic:

(1) investors can borrow and lend an unlimited amount of money at a risk-free rate;

(2) investors evaluate equity/security portfolios according to the means and standard deviations of portfolio returns;

(3) there are *no* income taxes; and

(4) investors are "single period expected utility of terminal wealth maximizers" -- that is a 100 percent liquidating dividend is paid at the end of the period.

Id., p 54. [emphasis added]. Clearly, investors would find highly desirable a world with unlimited investor borrowing capacity and no income taxes, but reality is otherwise. The CAPM assumptions try to fit all investors into one neat package to conform to the Model requirements. The requirements that investors evaluate their portfolio returns and liquidate their investments at the end of the holding period obviously cannot contain the many different investors with many different analysis techniques and investment requirements. Mr. Moul's analysis never attempts to address any of these fundamental problems with these assumptions of the Model. The Department should reject the use of the CAPM analysis as a methodology for determining the cost of equity for utilities, as it has done in the past. *Id.*

Mr. Moul's application of the CAPM analysis is also flawed. He assumes that all investors have a 20-year or greater investment horizon, since he used 20-year U.S. Treasury Bonds as the basis for his analysis. Exh. KEDNE/PRM-1, pp. 48-49. Of course, other investors have infinitely many investment horizons that will cause different return requirements. For instance, if one assumes that investors had a five-year investment horizon, then their CAPM required return would be:

CAPM Cost of Equity For
Five-Year Investment Horizon

Five-Year Yield	2.94%
Equity Risk Premium Over Five-Year Yields	7.40
Beta	0.81
Required Cost of Equity	8.93%

See Exh. AG-14-30, [Average of Nov. – April Five Year Yields] Exh. RR-AG-65, Equity Risk Premium, Table 9-2, and Exh. KEDNE/PRM-1, p. 48. If one assumes that investors had a thirty-day investment horizon, then their CAPM required return would be:

CAPM Cost of Equity For
Thirty-Day Investment Horizon

Thirty Day Yields	1.50%
Equity Risk Premium Over Thirty-Day Yields	8.40
Beta	0.81
Required Cost of Equity	8.30%

Id.

The returns required for any investors short of the thirty-year investment horizon used by Mr. Moul are significantly less than the 13.22 percent return that he uses as the recommendation from his CAPM analysis.[61]

For these reasons, the Department should reject Mr. Moul's CAPM analysis.

c. Comparable Earnings Analysis

Mr. Moul also performed a Comparable Earnings analysis. Exh. KEDNE/PRM-1, pp. 51-55 and Appendix I. He bases this comparable earnings analysis on certain stock indicators

[61] Mr. Moul also inflates his cost of equity recommendation by proposing to add a premium to his CAPM analysis to reflect the small size of Boston Gas. Boston Gas is now part of KeySpan, an S&P 500 Company and the fifth largest gas distribution company in the country, so no small equity risk premium is appropriate.

used by *Value Line Investment Survey*. Exh. KEDNE/PRM-1, pp. 53-55. The Department has repeatedly rejected the Comparable Earnings approach. *Boston Gas Company*, D.P.U. 96-50, pp. 131-132 (1996); *Cambridge Electric Light Company*, D.P.U. 92-250, pp. 160-161 (1993); *Bay State Gas Company*, D.P.U. 92-111, pp. 280-281 (1993); *Berkshire Gas Company*, D.P.U. 92-210, p. 155 (1993); and *Berkshire Gas Company*, D.P.U. 905, pp. 48-49 (1982). The Department specifically rejected Mr. Moul's use of the Comparable Earnings Approach as unreliable because the earned return on common equity did not necessarily equal the companies' cost of capital. *Berkshire Gas Company*, D.P.U. 905, pp. 48-49 (1982) *citing Boston Edison Company*, D.P.U. 1991, p. 56 (1979). Mr. Moul has provided no reason in this case for the Department to change its well-founded precedent. The Department should reject Mr. Moul's Comparable Earnings analysis, since its results are unreliable.[62]

d. Risk Premium Analysis

Mr. Moul also provided a Risk Premium Analysis. Exh. KEDNE/PRM-1, pp. 42-46 and Exh. KEDNE/PRM-1, Appendix G. Although he represents this methodology as an analysis separate and distinct from the CAPM analysis, it is essentially the same analysis. The cost of equity capital is equal to the yield on utility bonds plus an equity risk premium. *Id*. His risk premium analysis substitutes utility bonds for U.S. Treasury bonds and he substitutes the Standard and Poor's utility index for the stock market return. *Id*.

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[62] Mr. Moul's analysis of historical earned returns is fatally flawed by the exclusion of negative returns, a flaw that biases all of his results upwards.

The Department has reviewed and rejected Risk Premium analyses like Mr. Moul's many times before. See *Boston Gas Company*, D.P.U. 96-50, p. 128; *Massachusetts Electric Company*, D.P.U. 95-40, p. 97 (1995); *Boston Gas Company*, D.P.U. 93-60, p. 261 (1993); *Bay State Gas Company*, D.P.U. 92-111, pp. 265-266; *Berkshire Gas Company*, D.P.U. 92-210, pp. 138-139 (1993); and *Berkshire Gas Company*, D.P.U. 90-121, p. 171 (1991). Each time the Department has found that the risk premium approach overstates the amount of company-specific risk and, therefore, overstates the cost of equity. *Id*. The Company has provided no new analyses and no new argument. The Department should again reject Mr. Moul's Risk Premium analysis. *Id*.

Mr. Moul increased his cost of equity recommendations by creating new adjustments for certain cost or risk factors. These adjustments increase the cost of equity for his comparison group and ultimately for the Company. He proposes that his market-to-book ratio adjustment be applied to his DCF analysis, which would inflate his DCF results by 82 basis points. Exh. KEDNE/PRM-1, pp. 40-41. He also leverages and unleverages the betas used in his CAPM analysis, which inflates the results of the CAPM by 125 basis points or 1.25 percent [(0.81 - 0.68) x 9.84%]. Exh. KEDNE/PRM-1, pp. 47-49. Mr. Moul, however, ignores what is probably the most important single factor that investors consider when investing in the companies in the comparison group - the companies' non-utility businesses increase their risk for these companies.

The Department is setting rates for the regulated gas distribution business. Tr. 15, p. 1899. The allowed return on common equity should reflect only the market-required return for that business. Since each of the companies in Mr. Moul's comparison group is invested in other non-utility businesses, their costs of equity for the overall operations of the corporation will diverge from that of the utility operations. Whether the non-utility businesses are oil and gas exploration or power generation marketers, these other businesses have higher required returns on common equity. The Value Line Investment Survey explicitly recognizes the higher risks and expected return requirements associated with these other businesses in warning customers not to invest in those companies with such businesses. *See* Exh. AG-14-19. Mr. Moul completely ignores this critical factor, which would lower the cost of capital for the regulated gas distribution business.

2. THE DEPARTMENT SHOULD DISAGGREGATE THE COST OF COMMON EQUITY BY RATE CLASS.

The Department should disaggregate the allowed return on common equity when it determines the class-by-class cost of service to reflect the different investment risk associated with each rate class. Mr. Moul testified that residential customers are less risky to serve than commercial and industrial customers:

> A higher proportion of residential customers is a benefit to the Company because obviously the changes the chances of fuel switching are much less prevalent in that class of customer. Those customers will provide a much more stable base. I mean the industrial or transportation customers you have the impact of plant closures and all those types of things, which typically aren't an issue when it comes to residential customers.

Tr. 15, p. 1910.

The Company also recognizes the difference in rate classes when choosing hurdle rates for investments in main extensions to customers. The Company recognizes a 100 basis point difference in the cost of capital between the residential class and other classes of customers. Tr.

7, pp. 813-815. The Department should recognize the 100 basis point lower cost of capital for residential customers when it determines the class-by-class cost of service in the cost of service study.

The Department, then, should reject Mr. Moul's recommendations regarding the cost of capital. Instead, the Department should determine the cost of common equity based on a DCF analysis that results in an 8.99 percent allowed return. Furthermore, the Department should recognize the lower cost of capital for residential customers by disaggregating the allowed return on common equity to reflect the 100 basis point lower cost for residential customers.[63]

VII. RATE DESIGN

A. THE DEPARTMENT SHOULD REJECT THE COMPANY'S PROPOSED WEATHER STABILIZATION CLAUSE BECAUSE IT IS POORLY DESIGNED AND FAILS TO MEET THE DEPARTMENT'S REQUIREMENTS.

The Department has required the inclusion of a weather normalization adjustment in its gas utility revenue requirement determinations to avoid the skewing of the revenue in a test year, up or down, as a result of abnormal weather conditions. This adjustment, which is performed only during a rate case, is intended to normalize the company's test year sales volumes to a level that would have occurred had the test year been a "normal" weather year.[64] When the test year is colder than normal, test year revenues are reduced and, conversely, when the test year is warmer

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[63] If the Department reduces the risk to the Company by adopting a pension reconciliation mechanism or a weather stabilization adjustment, then the allowed return on equity should be reduced as discussed in those sections.

[64] "Normal", in the context of the weather adjustment made to the company's test year sales, refers to the average of the most recent twenty years' degree day experience.

than normal, test year revenues are increased. This also allows for a neutral allocation between ratepayers and shareholders of the risk that the upcoming rate year will be colder or warmer than normal, yielding more (colder weather) or less (warmer weather) revenues than the Department intended. *See Bay State Gas Company*, D.P.U. 92-111, p. 41 (1992).

In this case, the Company, in addition to weather normalizing its test year sales, has proposed a new Weather Stabilization Clause ("WSC"). In this new proposal, the Company would adjust customer billings every month to reflect its actual weather experience. In essence, customer bills will go down if the weather is colder than normal or up if the weather is warmer than normal.[65] Although the Company claims that this will protect the ratepayers from the volatility in their bills resulting from the unusual cold (Exh. KEDNE/JFB-1, p. 45), the end result will be the stabilization of the Company's revenues. Exh. KEDNE/JFB-1, p. 45.

More than a decade ago, when the Department last reviewed WSC proposals, it rejected them for a variety of reasons. *See Bay State,* pp. 58-59 *and Berkshire Gas Company*, D.P.U. 92-210, p. 196 (1993). The Department found that WSC's: (1) do not equitably share the potential risks and benefits between ratepayers and shareholders; (2) do not respond to the increasing application of competitive market forces in the allocation of energy resources; (3) are not based on reliable weather data; and (4) they would have resulted in rates that were not just or reasonable. *Bay State*, D.P.U. 92-111, pp. 57-61, *Berkshire Gas Company*, D.P.U. 92-210, pp.

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[65] The Company has proposed to implement the bill adjustment whenever temperatures are in excess of 2 percent of normal–either higher or lower. The proposal includes an annual update filing with the Department with its annual PBR compliance filing, which will show the elements that will effect customers' weather normalized bills under the terms of the WSC adjustment.

191-199, (1993). The Company's WSC suffers from the same defects the Department noted a decade ago.

First, the proposed WSC proposal will significantly reduce its weather-related risks and shift them to the ratepayers. The Department has clearly stated that any such reduction in risk on equity investments for the company should be shared commensurately with the company's ratepayers through a reduction in the rate of return on equity. *Bay State*, D.P.U. 92-111, pp. 60-61. Indeed, the Department held that it not even review a WSC proposal unless that the proposal provides a commensurate adjustment in the company's allowed cost of capital. *Berkshire Gas Company*, D.P.U. 92-210, p. 199, (1993). Boston Gas has not proposed nor calculated any adjustment to its cost of equity to reflect this proposed reduction in risk. Consistent with precedent, the Department should reject the proposed WSC.

Secondly, the Department has rejected other WSC proposals because they represent a movement back to cost-based regulation and away from market based regulation. *Bay State*, D.P.U. 92-111, p. 58; *Berkshire*, D.P.U. 92-210, p. 196. Since the first WSC proposals the Department has opened the retail market for all customers and rates have been fully unbundled to facilitate the development of the competitive market. If the Company's goal is to protect ratepayers from volatility in their bills, the Department should take the opportunity to consider the propriety of WSCs for all Massachusetts customers as part of a generic investigation into how best to serve the interests of customers given the outlook for retail residential competition.[66] A generic investigation would provide a platform to more fully explore issues common to all

[66] The Department has recently recognized that competitive options do not exist for small customers and has expressed its willingness to review proposals to mitigate commodity price volatility. *Bay State Gas Company*, D.T.E. 01-81, p. 27 (2002).

Massachusetts LDCs, including price signal issues.[67] The Company's WSC is anti-competitive in that it would send distorted price signals to customers by raising prices in warmer weather. This is contrary to the Department's goal of providing consumers with the correct price signals to link consumption incentives to cost incurrence. The Department should reject the Company's WSC and open a generic docket to address the volatility of gas rates.

Consistent with previously rejected WSCs, the Company does not have reliable weather data. The Company's WSC proposal uses the normal degree day information from one location, Logan Airport, that is not representative of weather throughout the Company's service territories. Exh. AG-8-29. The Logan information is used to calculate the heating increment factor for the weather adjustment in the WSC proposal. The heating increment factor is calculated at each rate-class level, not at the customer level. Tr. 3, p. 275. The customers in the Company's various service areas experience different weather than those customers in the same rate-class that actually experience the weather conditions recorded at Logan Airport and therefore, experience different usage levels. By calculating this heating increment factor at a rate-class level, the Company is ignoring those customers that experience different weather conditions from Logan Airport and will not accurately implement the WSC adjustment on those customers' bills. Consistent with precedent, the Department should reject the WSC proposal because the weather data on which the weather adjustment depends is unreliable.

Finally, the proposed WSC results in rates that are not just or reasonable. The Company's proposed WSC applies to both weather-sensitive (heating) and non-weather-sensitive

[67] The Attorney General has made a similar request in his Initial Brief in *Bay State Gas Company Forecast and Supply Plan, 2002-2007*, D.T.E. 02-75, p. 1. for the Department to open a generic investigation to develop a comprehensive plan for retail natural gas competition in Massachusetts.

(non-heating) customers. The Department should not allow a WSC adjustment to non-heating customers because their gas use is not weather sensitive. No weather-related adjustments should be made to non-heating customer bills. The Department previously expressed concerns about possible unfair intra-class subsidization if non-heat sensitive customers are included in a WSC. *Bay State*, D.P.U. 92-111, p. 58. This intra-class subsidization could result in customer confusion and dissatisfaction among non-heating customers upon realizing that their bills vary with weather changes. Such customer confusion contradicts the Department's rate design goal of simplicity and consumer understanding.

Unjust and unreasonable rates will result from the fact that the tailblock rate used in the calculation of the proposed WSC is at marginal cost for the residential rate classes but not for the commercial and industrial rate classes, whose tailblock rates are higher than the marginal cost. Exh. KEDNE/ALS-5 (Revised), p. 1; Exh. KEDNE ALS-2, Schedule 11, p. 1; RR-DTE-4(a). Since all of the classes' tailblock rates are not at marginal cost, one rate class is likely to be subjected to a higher weather adjustment than another rate class. As the Company's witness, Mr. Silvestrini, testified, the use of the marginal cost gives the most appropriate signal regarding weather sensitivity. Tr. 3, pp. 277-278. The Company's rate design, which sets only the R-1 and R-3 classes' tailblock rates at marginal costs, will result in these classes having significantly diminished bill impacts under the Company's proposed WSC; thus creating an inequality among the rate classes as to how much of a burden each rate class will bear. The Company has not established that the WSC will result in just and reasonable rates.[68]

[68] During the test year the Company converted to the KeySpan billing system. The conversion resulted in customers' bills being prorated to reflect the actual number of billing days in each bill and more frequent bill adjustments for level bill payment plan customers. The new billing system was

For all of the reasons stated above, the Department should reject the Company's WSC proposal. The Company's WSC proposal is poorly designed and will not function as the Company claims. Any benefit that ratepayers could possibly receive from the adoption of this proposal are far outweighed by its numerous inherent problems.

B. THE DEPARTMENT SHOULD ORDER THE COMPANY TO PROVIDE, IN ITS COMPLIANCE FILING, JUSTIFICATION FOR THE CONTINUED USE OF ITS RATE DESIGN MODEL AND PROOF THAT IT HAS CORRECTED ERRORS IN THE LOW INCOME BILLING DETERMINANTS.

In designing the Company's proposed base distribution rates, the Company relies on several rate design spreadsheet models.[69] One model develops class rates based on the Company's fully allocated cost of service study. Exh. KEDNE/AEL-5. Another spreadsheet model is used to determine, through an iterative process, the amount of the low income discount to be recovered from the other rate classes.[70] Exh. KEDNE/ALS-3 and ALS-4.

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responsible for several adjustments to the test year cost of service–one related to the way energy conservation revenues were being reported and another related to penalty revenues. Tr. 6, p. 701, pp. 690-691. The calculation of the heating factor was also incorrect due to the conversion to the new billing system. RR-DTE-22. The Company has not provided any evidence that the system is functioning appropriately and the customer bills are being computed correctly according to approved DTE tariffs. Prior to the implementation of any sweeping change to how customer bills are calculated, the Department should consider requiring an audit to establish whether the billing system software complies with tariff terms and whether the bills generated by the system are accurate.

[69] The Department analyzes the results and accuracy of companies' computer models and spread sheet calculations made by companies by reviewing the data input and the output. The Department has accepted the Company's use of its billing system to determine its weather normalization adjustments to test year revenues and volumes (bill determinants) with the requirement that the Company also provide the same adjustment calculated using another method to validate the billing systems calculations. *Boston Gas Company*, D.P.U. 93-60, pp. 78-79 (1993) (approving the use of a per customer and bill-by-bill based adjustment independently validated by using the existing rate class aggregate method).

[70] The rate design spreadsheet models are in fact contained in a single Excel file. Exh. AG-13-3 (electronic versions of Exh. KEDNE/ALS-3 and 4 (revised))

The Company initially filed proposed rates that were generated using a rate design model that included a cell reference error. Exh. KEDNE/ALS-8, p. 2. The error involved the exclusion of the customer charge revenues when designing the energy component of the R-3, residential heating class rates. *Id*. The Company filed exhibits (KEDNE/ALS-3, ALS-4, ALS-5 and ALS-7) correcting all base distribution rates on May 7, 2003 and reflected corrections to all pre-filed base distribution rates. Any error in the R-3 rates affects all rate classes because the low income subsidy is allocated to all of the Company's other customers and collected through the base rates.

During the proceedings, the Company admitted that there was another cell reference error related to the Company's method of computing the low income classes billing determinants (the number of bills and volumetric use) used to determine the distribution rates. RR-AG-17. The Company's witness testified that the error had been identified while the witness was preparing for hearings and the Company planned to file corrected exhibits.[71] Tr. 24, pp. 3311-3313.

The error is the result of an invalid cell reference in the denominator used to determine the low income allocators (non-heating and heating). The cell shows the sum of two cells. The

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[71] The Company relied on a single month's data, March 2003, for the number of bills for the low income classes. The actual March 2003 number of bills was multiplied by 12 to determine the annual number for designing the customer charge for the low income classes. The cost of service study allocates costs to two residential classes, heating and non-heating. It does not segregate the low income heating and non-heating classes. Exh. KEDNE/AEL-5. In the rate design process, the Company aggregates the number of bills and the billed volumes into residential heating and non-heating categories. Because of this aggregation the Company chooses to create the low income bill determinants by using an allocation factor ("the low income allocator") that is the ratio of the March 2003 actual number of bills for the low income heating and low income non-heating class to the total residential heating and the total residential non-heating number of bills for the test year. Exh. KEDNE/ALS 3&4 (revised, electronic spreadsheets, Input worksheet, cells D-4, 5 and 6 and cells D-11, 12 and 13, non-heating and heating, respectively). The allocation factor is multiplied by the monthly aggregated data for the number of bills and the block volumes to produce the bill determinants for the low income classes. The regular heating and non-heating class determinants follow the same process except the allocation factors are simply one minus the related low income allocator.

first cell is the peak season number of bills for the combination of the R-1 and R-2 classes and for the combination of the R-3 and R-4 classes. The second cell should logically have been the off peak season number of bills, but instead it was a blank cell. Only the peak season data therefore was used in calculating the allocator, understating the denominator by approximately 50 percent and approximately doubling the R-2 and R-4 allocator. When the allocator was applied to the aggregated bill and volume data, it doubled the number of low income bills used to develop the low income customer charge and doubled the head and tail block volumes. When these overstated volumes were used to create the rates, the low income discount was also doubled, increasing the revenue requirement for all other classes. The cell reference error also, more subtly, understates the non-discounted residential rates (R-1 and R-3). These class rates were higher than if their bill determinants had been at correct levels because these rates were being designed to recover their revenue requirement over fewer billing units. *Id.*; Tr. 24, pp. 3229-3240; and Tr. 24, pp. 3313-3314.

The low income bill determinant error is serious. If it had not been corrected, the Company would have overcharged customers $4 million annually. This amount would have been increased each year by any annual PBR formula, and could have produced a windfall to the Company of over $25 million during a five year PBR period, assuming an annual PBR increase of 3% and a 2% annual load growth.

The Company has continued to use a model that has produced erroneous results several times in several cases. The Company admits that the allocation of low income discount was the source of an error in the first PBR compliance filing after D.P.U. 96-50,[72] but the Company did not scrutinize the results of using the same model again in preparing the proposed rates in this case.[73] Human errors of course occur, but the Department should not allow a pattern of repeated errors with the same model. The Company's proposed rate design must be based on an accurate and reliable model. The Department should order the Company to provide evidence demonstrating that its models are accurate and that the Company rigorously reviews and validates its proposals. The Company has failed to do so in this case. The Department should require the Company to provide sufficient support for the continued use of its rate design model in the compliance filing. The Company should be required to provide proof that the low income bill determinants are valid, as was requested in RR-AG-17, and provide all proofs and tests it has done to validate the compliance filing results.

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[72] On the question of whether the error was present in establishing the PBR adjustments, the Company claims that the error was corrected by abandoning the use of the model in the initial (after full adjudication in D.P.U. 97-92) and in all subsequent PBR filings. RR-AG-96.

[73] The Company has not provided sufficient evidence that the low income allocator developed in the same model does not still suffer from the same infirmity as in the Company's last cast-off rate case, resulting in the overstatement of the low income discount. The Company did not provide the model it relied upon in the D.P.U. 96-50 compliance filing in response to RR-AG-98 until late on August 22, 2003, and still had not provided the electronic files supporting the recalculation of the proposed rates correcting the cell reference error as of August 22, 2003, more than 2 weeks after the Company claimed to have already prepared this filing.

C. THE DEPARTMENT SHOULD OPEN A GENERIC INVESTIGATION INTO THE NEED FOR MARGIN SHARING.

The Department has allowed gas distribution companies to share margins from certain transactions as an incentive to encourage the companies to mitigate the related costs born by the Company's firm tariffed customers.[74] *Interruptible Transportation*, D.P.U. 93-141-A and D.P.U. 93-141-B (1996). The transactions that are subject to margin sharing, which are also referred to as opportunity sales, fall into four categories:

1. Interruptible transportation margins–revenues generated from transportation to customers that may be interrupted by the Company under specific conditions,

2. Off-system sales margins–revenues from sales of upstream gas or capacity to customers outside the LDC's service territory,

3. Capacity release margins–revenues from the sale of upstream pipeline or storage capacity, and

4. Interruptible sales margins–commodity sales made on an interruptible basis.

Margins above annual thresholds are shared on 75/25 percent basis, with the Company retaining the 25% share. The Department requires companies to benefit all distribution customers by crediting a customer's share of margins on interruptible sales, capacity release[75] and off-system sales through the CGA, and a customer's share of interruptible transportation margins

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[74] The Department found that margin sharing would provide an ". . . incentive for future action by LDCs to maximize the efficiency of the local distribution system." D.P.U. 93-141-B, p. 4, referring to D.P.U. 93-141-A, pp. 11-12.

[75] The Company has had asset management arrangements since 1997. The asset manager makes a fixed payment to the Company and uses the Company's gas portfolio as it sees fit so long as the Company's load is served at the agreed upon prices. The bulk of the Company's test year capacity release revenue is related to the asset management arrangements in place during the test year.

through the Local Distribution Adjustment Clause ("LDAC"). *Id*. The thresholds are set annually and are based on a prior 12 months of margins for each of the four categories. The Company can only share in margins generated in excess of the prior year's margin level in each category. *Id*., D.P.U. 93-141-B, pp. 4-5.

During the test year the Company generated the following revenues in each of the margin sharing categories :

Interruptible transportation margins	$ 109,194
Off-system sales margins	2,466,722
Capacity release margins	8,688,543
Interruptible sales margins	3,681,179
Total	$14,945,638

Exh. AG-8-21.

The Company proposes to eliminate each of the thresholds but retain the 25/75 margin sharing arrangement. Exh. KEDNE/JFB-1, p. 52. The Company supports its proposal by arguing (1) circumstances have changed since 1996 when the Department made its margin sharing decision, and (2) it wants to "ensure that customers receive the maximum possible benefits for the use of its resources, both on-system and off-system." *Id*.

The Company asks to retain, for the benefit of its shareholders, 25 percent of all revenue the Company generates under off-system sales agreements, interruptible transportation agreements, and capacity release agreements.[76] Tr. 21, p. 2849. On the question of whether Boston Gas has unique issues or problems with its margin sharing rules, or whether any changes to the Department's margin sharing policy should be done in a generic proceeding, the

[76] Interruptible sales margins are revenues minus the cost of gas allocated to serve these customers.

Company's witness focused only on the lack of alacrity in prior generic investigations. Tr. 21, pp. 2858-2859.

The Department has determined that companies should receive an **incentive** to enter into these types of arrangements to mitigate costs to firm customers–not a perpetual "cut" of revenues for which the Company does not expend effort or money to generate on a continuing basis. Tr. 21, pp. 2851-2852. The Company's proposal would turn an incentive into a payment, contrary to the Department's intent.

There have been changes in the industry and within the state that could possibly support a change in the Department's policy. These changes, however, affect most of the LDCs in the state and are therefore better addressed on a generic basis where all interested parties may be heard. The Department should open a generic investigation into the need for margin sharing, the changes that have affected the categories of costs currently subject to margin sharing and the future policy that might provide the appropriate cost mitigation to customers and the appropriate incentives, if needed, to the LDCs.

D. THE COMPANY'S PROPOSED CUSTOMER CHARGES VIOLATE THE DEPARTMENT'S RATE CONTINUITY GOAL.

The Department requires companies' rates to balance the following goals: (1) efficiency (rates should recover the cost of providing service and provide the appropriate signals to customers regarding energy decisions they make); (2) simplicity (rate provisions should be easily understandable); (3) continuity (changes to rates should be gradual, allowing customers to adjust consumption patterns in response to changes); (4) fairness (no customer class should pay more than the cost to serve it); and (5) earnings stability (rate revenues should not vary significantly over a period of one or two years). *Berkshire Gas Company*, D.T.E. 01-56, pp. 134-135. The Company's rates do not properly balance these goals.

The Company sets the proposed customer charge for each rate class at a level below the embedded customer service related costs[77] in order to address rate continuity issues. It then sets rate blocks to recover the remaining class revenue requirement. For the residential classes, the Company sets the tail block charge at the class's marginal cost and adjusts the head block then to recover the remaining revenue requirement.[78] Exh. KEDNE/ALS-1, pp. 24-30.

The Company's proposed rates produce significantly high bill impacts despite any attempt to address continuity concerns. *Id*. The impacts are greatest for the customers with lower than average use because customer charges represent a greater proportion of their bills. The proposed increase for the residential heating class customer charge is approximately $7 per month (from the current $10 to $17), an increase of almost 70 percent. Based on the Company's own analysis, 20 percent of the customers in the residential heating class will have winter bill increases of approximately 20 percent. Exh. KEDNE/ALS-5 (revised), p. 9. Residential customers with lower usage will see even steeper percentage increases. Similarly, in the small commercial customer (G-41) class, more than 40 percent of the customers will see increases in

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[77] For the residential classes, the Company proposes to set the customer charge at 33 percent of the Company's embedded cost to provide customer services to each of the residential classes. KEDNE/ALS-1, p. 24.

[78] Issues associated with the use of the marginal cost for setting the tail block rate for only the residential classes is discussed in the section addressing the Company's Weather Stabilization Clause proposal.

their winter bills in excess of 20 percent.[79] *Id.*, p.10. Although the percentage increases are not as dramatic for other classes, the proportion of low use customers is greater in some classes; the number of customers seeing higher than average increases will differ between classes.

In the Company's prior rate case, the Department rejected the Company's request to increase the residential customer charges by $3 per month for the non-heating class and $6.50 for the heating class. Instead, the Department, citing continuity concerns, ordered the Company to increase both the non-heating and heating residential rates by only $1 per month. *Boston Gas Company*, D.P.U. 96-50, p. 156. In order to control bill impacts at a time when customers are already suffering from large CGA increases, the Department should deny the Company's proposed customer charge increases and allow only a slight increase in residential and small commercial customers' charges, as in the prior rate case.

[79] The off peak or summer bills for the residential heating and G-41 classes have substantially lower volumes and therefore the customer charge is an even greater proportion of the bill. The Company's analysis shows that the residential heating bills for the lower use customers will increase by almost 50 percent and by 35 percent for the lower use G-41 customers. *Id.*, pp. 15 and 16.

VIII. THE PROPOSED PBR PLAN

A. THE DEPARTMENT SHOULD REJECT THE COMPANY'S PROPOSED PBR PLAN BECAUSE IT IS CONTRARY TO DEPARTMENT GOALS AND UNFAIR TO RATEPAYERS.

The Company has proposed an "inflation-plus" rate plan that more resembles a cost of living adjustment ("COLA") for the Company than a performance-based rate ("PBR") plan. The Company proposes that it be allowed to increase rates by more than the rate of escalation in the Gross Domestic Product. Exh. KEDNE/LRK-1. The Company's "COLA" presents significant risks to customers and little prospect of benefits; it will most likely result in customers paying more, not less, than they would under cost of service ratemaking.

The Company's proposed adjustment to the inflation index is based on a number of unduly complex, "black box" analyses that purport to be very precise, but are actually a case of false precision and are effectively unreviewable within the six month schedule of a rate case, even with expert assistance.[80] The Department should consider whether, absent intervenor experts reviewing the proposal, it could adequately assure within a six month suspension period that all of the models and analyses produce accurate and reliable results, in addition to evaluating the proposal and all of its policy ramifications. The Company does not adequately support either its black box analyses or its proposal for a very small consumer dividend.

The Department requires a utility seeking approval of an incentive proposal to demonstrate that its approach advances "the Department's traditional goals of safe and reliable energy service and . . . promote[s] the objectives of economic efficiency, cost control, lower

[80] On May 23, 2003, the Attorney General requested that the Department sever the PBR portion of this case and address the incentive mechanism in a follow-on proceeding. Tr. E, pp. 11-12.

rates, and reduced administrative burden in regulation." *Incentive Regulation*, D.P.U. 94-158, p. 57 (1995). The Company's proposed PBR mechanism fails to meet the Department's standards for approval of an incentive proposal.

The Company has not proposed a traditional PBR, but offers a "hybrid" between a cost of service model and an incentive model. Boston Gas seeks the best of both worlds with high cast-off rates ($61 million proposed rate increase) that are then increased automatically for years under an inflation-plus PBR formula. Exh. DTE-6-1 (initial and supplemental)(electronic spreadsheets). The Company appears to have delayed plant improvements during the first several years of its PBR, and then accelerated capital improvements before the end of the test year to maximize rate base. *Id*. KeySpan also appears to have increased Boston Gas expenses during and soon after the test year, by, among other means, allocating large amounts from affiliates. The Company has offered no convincing argument that its hybrid PBR would help the Department achieve its traditional goals better than existing rate setting methods.

The Company's PBR proposal makes no allowance for expiration of the 10 year merger rate freezes ordered by the Department for Essex and Colonial Gas. Tr. 10, pp. 1234-1237; Tr. 11, 1340-1343, 1379-1381. Under the system of cost accounting allowed by the Department in those cases, Essex and Colonial Gas retain the synergies from the mergers to pay for merger related costs. Eastern/Essex Merger, D.T.E. 98-27, p. 69; Eastern/Colonial Merger, D.T.E. 98-128, pp. 90-96. Once those rate plans end, costs to Boston Gas should fall dramatically as it also continues to see the benefit of those mergers. The customers of Boston Gas should share in the benefits of these mergers after the freeze period, but the Company's PBR proposal does not share those cost savings with the customers of Boston Gas in any way. Boston Gas will enjoy a windfall at the expense of consumers.

Boston Gas proposes as a productivity measure that a negative "X" factor (-0.2%) be subtracted from inflation as measured by the Gross Domestic Product Price Index ("GDP-PI"), resulting in gas delivery rates increasing at a rate of 0.2% more than the general inflation rate [(GDP-PI)-(-0.2%)]. Exh. KEDNE/LRK-1. The Company develops the X factor by considering such matters as expected productivity gains and the relationship between gas input prices and other input prices. *Id*. The Company presented as support for this proposal a number of unduly complex studies performed by Dr. Lawrence Kaufmann of Pacific Economics Group ("PEG") that purport to address "normal" gas distribution prices increases and Boston Gas' economic efficiency. The Company has not shown that normal gas utility costs increase faster than the GDP-PI, or that a reasonable Consumer Dividend is only 0.15%.

The first component of the X factor, the productivity index, is supposed to reflect the difference between productivity changes in the gas industry versus in the overall economy. The second component, the input price index, should indicate how the rate of change in prices of inputs used by gas utilities compares to the general price deflator. Dr. Kaufmann produced a productivity study that estimated the total factor productivity ("TFP") growth of 16 gas utilities in the Northeast from 1990 to 2000, then submitted another study which analyzed the same data for 1990-2001. The first study concluded that the annual productivity increase of these Northeast gas utilities was less than the private business sector as a whole, and the second study found a smaller differential.

Dr. Kaufmann has not adequately justified limiting his analysis to 16 large northeastern gas distribution companies. RR-DTE-76. The Company presented no evidence showing that the 16 utilities in the Northeast are representative of the 50 utilities, or that smaller gas utilities would have different rates of productivity growth. Exh. AG-41, p.6. Nor has the Company provided evidence that the factors that result in productivity growth are different in the Northeast than in the rest of the country. It is evident that nationwide differences between utilities as a whole and the total business sector are small and vary in direction. The differences between the gas industry and the total business sector, nationwide, do not indicate that gas costs will increase more than output prices of the total business sector. Dr. Kaufmann testified that the sources of productivity gains include technological change, economies of scale, the elimination of inefficiencies, and the degree of capacity utilization. Lee Smith of LaCapra Associates testified for the Attorney General that "[t]hese factors do not have obvious regional characteristics and, indeed, [Dr. Kaufmann] has not stated directly that they do." Exh. AG-41, p.5.

The Company's productivity study is flawed beyond the question of whether the northeastern sample is adequate. There are errors in cost data in the first and last years for some companies. RR-DTE-76. Understating cost in the first year and/or overstating cost in the last year will have the effect of reducing productivity growth. *Id.* Dr. Kaufmann agreed that several years of data were in error, and that correcting them made some difference. Exh. AG-12-10; Exh. AG-31-11; Tr. 10, pp.1178-1182.

Dr. Kaufmann's study period did not correspond perfectly to the business cycle. RR-DTE-76. Growth during this business cycle was higher than normal, so this period may not have had normal productivity growth for the gas industry. Dr. Kaufmann did not test this, maintaining that such correspondence did not matter.

The largest single problem with Dr. Kaufmann's productivity study is its estimation of capital cost, which suffers from numerous inaccuracies. RR-DTE-76. If a large component of utility cost is misstated, this can obviously bias the results. The vintaging that is supposed make plant of different vintages comparable will tend to understate the value of older plant, since it acts as if the plant value in 1983 was the same age and had been installed at the same rate for all utilities. *Id*. PEG does not even know the average age of plant by utility. *Id*.

Whatever the Company's actual increase in costs has been, moreover, according to the Company, it is now providing improved outputs. Mr. Bodanza has testified that the Company's actions over the last two years have provided customers with different products and improved reliability. Unless this level of service change continues, we should not see a continuation of the incremental costs that provided these service level changes. The measure of output used in the productivity study does not reflect the introduction of new products, and the improvement in service reliability.

The third component of the X factor, the consumer dividend, is intended to reflect the expectation that total factor productivity growth will increase under PBR. The Company claims, however, that it expects that any such growth will be very small.

Dr. Kaufmann claims that Boston Gas is already a "superior cost performer". He bases this conclusion entirely on results of the PEG econometric model of gas utility costs, which remains an unreviewable "black box." This "black box" suffers from a number of problems, including study design and cost measurement, and so does not prove that Boston Gas is an efficient performer.

Dr. Kaufmann's econometric cost study is also flawed because it does not include a number of variables that probably influence cost. RR-DTE-76. The absence of these variables is likely to make Boston Gas appear a more efficient performer. *Id*. This study does not even examine Boston Gas's actual costs, for various reasons. The primary reason is the entire definition of the capital cost is itself the result of another black box analysis. Ms. Smith identified numerous problems with the capital cost estimation, most of which would tend to bias the study in a direction that would appear to make Boston Gas appear to be low cost when it was not. The econometric cost study has the same capital measurement problem as the productivity study: it makes Boston Gas appear to be a low cost utility because the value of its old mains is understated. *Id*. The capital cost component includes actual taxes paid by each utility, although lower taxes do not mean higher efficiency. *Id*. Relative to its capital plant cost, Boston Gas pays a much lower amount of taxes than most of the utilities in the Northeast study. *Id*. Dr. Kaufmann should not identify Boston Gas as an efficient performer because it has a lower tax rate than others in the study, but he appears to have done so. Ms. Smith testified: "I don't think that the PEG study demonstrates that Boston Gas has already achieved great efficiencies." Exh. AG-41, p. 16.

While Mr. Bodanza (Exh. KEDNE/JFB-1, p.24) and Dr. Kaufmann both argue that the Company has already increased efficiency so that there is little room for additional improvement, there is much evidence that productivity gains will accelerate. Economic theory, including a source cited by Dr. Kaufmann,[81] suggests that economic efficiency will increase as the Company continues to adjust its operations in response to the incentives created by PBR and the mergers and to react more efficiently to technological change. Boston Gas has not proved its claim that it cannot find significant additional efficiencies because it was under rate cap regulation from 1997 to 2001. Ms. Smith testified that "if PBR is effective in changing management incentives, this will have an impact not only on how existing operations are performed, but also on how the utility will react to technological change." Exh. AG-41, p. 23. There is empirical evidence that Boston Gas has not instituted many easy productivity improvements related to energy saving software activation. RR-AG-77; RR-AG-54. There is evidence that Boston Gas is planning to make a number of substantial efficiency improvements starting in 2003. Exh. KEDNE/JCO-14; Tr. 18, pp. 2464-2466.

The Company's claims are fundamentally inconsistent with the rationale for Performance Based Ratemaking. If the utility cannot be expected to improve its productivity growth rate under PBR, there is little justification for utilizing PBR rather than standard cost of service ratemaking. The Company has not demonstrated that its proposed PBR is better for customers than cost of service ratemaking. Ms. Smith testified that "PBR creates a risk that customers will pay more than they would under cost of service ratemaking (in other words, more than reasonable costs), so it is particularly important that this risk be balanced by the possibility of significant benefits." The California PUC justified increasing the consumer dividend by noting

[81] There is theoretical support for continued and even increased productivity gains in an article produced by Dr. Kaufmann from the Electricity Journal, "Efficiency as a Discovery Process: Why Enhanced Incentives Outperform Regulatory Mandates, " which states: " ... the achievement of performance gains is first and foremost a "discovery process' in which more efficient operating practices and superior use of technology are learned over time." Exh KEDNE/LRK-6, p. 59.

that productivity improvements do not occur all at once, but take time to implement. Order CAPUC docket 99-05-030, p.53.

The Department should instead allow a PBR for the Company only if it is reviewable and not unduly complex. A PBR also should have at least a 1% consumer dividend to allow customers some share of savings benefit. RR-DTE-72. Customers should also be allowed to benefit through an earnings sharing plan. Sharing should only be on excess earnings, not earnings below the authorized return, because the Company has far greater knowledge of its data, and ability to control, and even manipulate, its earnings figures, especially after multiple mergers. *Id*. A PBR should not be used with the proposed pension/PBOP reconciliation adjustment mechanism because that would double-count cost changes. *Id*. A PBR for the Company should include an appropriate exogenous change factor that reflects cost reductions as well as increases, but not the Company's proposed new formulaic capital replacement provision. RR-DTE-74. A PBR should adjust for savings at the end of the Colonial and Essex rate freezes, perhaps by removing the inflated value of costs reallocated back to Boston Gas. RR-DTE-74 and 75.

B. THE DEPARTMENT SHOULD REJECT THE PBR BECAUSE THE COMPANY HAS VIOLATED STATUTORY STAFFING LEVEL REQUIREMENTS.

The Department also should deny Boston Gas Company's request for a PBR plan because its reduction in staffing levels for the years since the expiration of the prior PBR violates the statute and the Department's criteria. G.L. c. 164, § 1 E(b); *Incentive Regulation*, pp. 52-66 (1995).

The Legislature explicitly integrated the provisions governing staffing levels with the requirements regarding a company's service quality. The statute states that,

> In complying with the service quality standards and employee benchmarks established pursuant to this section, a distribution, transmission, or gas company that makes a performance based rating filing after the effective date of this act shall not be allowed to engage in labor displacement or reductions below staffing levels in existence on November 1, 1997, unless such are part of a collective bargaining agreement or agreements between such company and the applicable organization or organizations representing such workers, or with the approval of the department following an evidentiary hearing at which the burden shall be upon the company to demonstrate that such staffing reductions shall not adversely disrupt service quality standards as established by the department herein.

G.L. c. 164, § 1E (b).

In 1997, the Legislature recognized that without this mandatory requirement, companies would attempt to reduce costs by decreasing staffing levels, which would adversely affect the quality of service provided to ratepayers.[82]

The Department's standard of review for evaluating PBR proposals provides that incentive plans may not result in a reduction in service quality. *Incentive Regulation*, D.P.U. 94-148, pp. 52-66 (1995). The Department established seven specific criteria to be used in evaluating incentive proposals. *Boston Gas Company*, D.P.U. 96-50 (Phase I), pp. 243-244, citing *Incentive Regulation*, pp. 58-64. The first criterion states that incentive proposals, "must comply with Department regulations, unless accompanied by a request for a specific waiver." *Id*. The Department added that "incentive proposals that comply with statutes and governing

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[82] *See* Letter to Berkshire Gas Company from Representative Daniel E. Bosley, copied to Chairman Paul Vasington, April 22, 2003, stating that G.L. c. 164, § 1 E (b) applies to a company that makes a performance based rate filing. Pursuant to the provisions of 220 C.M.R. 1.10 (3), the Attorney General asks the Department to incorporate this letter by reference.

precedent are strongly preferred." *Id*. The third criterion provides that, "incentive proposals may not result in reductions in safety, service reliability or existing standards of customer service." *Id*.

The generic guidelines ("Guidelines') issued by the Department regarding staffing levels in *Service Quality Standards for Electric Distribution Companies and Local Gas Distribution Companies*, D.T.E. 99-84, pp. 41-42 (June 29, 2001), state that: "Consistent with G.L. c. 164, § 1E, staffing benchmarks will be established on a company-specific basis and will be determined by the then-effective collective bargaining agreement for each company." *Id*.

The Company is subject to the mandatory staffing level requirements in G.L. c. 164, § 1E(b), because the prior PBR expired on November 1, 2001 *(Boston Gas Company*, D.P.U. 96-50 (Phase I) (1996), p. 320), and the Department rejected Boston Gas' request for a one year extension.[83] The Company's new PBR filing in April, 2003, triggered the mandatory staffing level provisions of G.L. c. 164, § 1 E(b).[84] The Company reduced staffing levels at Boston Gas Company from 1,445 in November 1997 to 798 in June 2003. RR-AG-3 [supp]. The Company also reduced staffing levels after the filing date of the current PBR.[85]

The Company has not sought nor received Department approval in any evidentiary proceeding to reduce staffing levels, nor has it attempted to demonstrate in any evidentiary proceeding that its unauthorized and unilateral staffing reductions will not adversely disrupt established service quality standards. The Company took no steps to avail itself of exemptions authorized by statute nor did it make any attempt to comply with the Act. The Company could have reduced staffing levels through collective bargaining or by petitioning the Department to

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[83] Letter Order *Boston Gas Company*, D.T.E. 02-37, August 6, 2002.

[84] In *NSTAR Service Quality*, D.T.E. 01-71 A, p. 8 (2002), the Department noted that the staffing level requirement under G.L. c. 164 § 1E applies to companies that file PBRs.

[85] The Company reduced staffing levels at Boston Gas from 767 in April 2003, to 764 in May 2003. RR-AG-3 [supp].

open an evidentiary proceeding, yet, the Company chose to do neither. The collective bargaining agreements submitted by Boston Gas (only upon request of the Attorney General) do not authorize a reduction in employee staffing levels. Exh. AG-1-42.

Instead of complying with the mandatory provisions of the statute or seeking an exemption, the Company claims that service quality is "not an issue in this proceeding" (Tr. 12, p. 1559) and that it is not subject to the law because its prior PBR exempts it from the applicability of these provisions. RR-AG-5. The Company errs on both statements. The issue of service quality is inextricably linked to the Department's evaluation of a company's PBR filing. *Incentive Regulation*, pp. 52-66 (1995). The Company is not exempt from the provisions of G.L. c. 164, § 1(E)(b) because the prior PBR expired on November 1, 2001, and the Department rejected a proposal to extend it beyond its expiration.[86]

The Company admits that in 2001 and 2002, employees of Boston Gas, Colonial Gas, and Essex Gas were transferred to KeySpan Corporate Service Company, LLC (the "Services Company," which was formed as a result of its merger with Eastern Enterprises). Exh. AG-22, Company Response to DTE-1-2. The Company notes that the employees who were transferred to the Services Company perform the same duties as they had in the past, but on a shared basis for the three Massachusetts LDC's. *Id*. The reduction in staffing levels at the distribution company, however, violates the statute even if there are increases at the Service Company. G.L. c. 164, §1E(b).

The Department should reject the current PBR because it does not meet the Department's guidelines for Incentive Regulation regarding staffing levels and service quality. In addition,

[86] See *Boston Gas Company*, Letter Order at 2, August 6, 2002. In fact, on August 23, 2001, the Department ordered the Company to file a proposal to succeed the PBR plan by September 15, 2001. *Boston Gas Company* Letter Order, August 23, 2001. The Letter Order also required that the proposal include "a service quality plan consistent with the guidelines established in Service Quality Standards for Electric Distribution and Local Gas Distribution Company, D.T.E. 99-84 (June 29, 2001). The Company did not file a successor PBR as ordered until this proceeding.

because the Company has violated the staffing level service quality provisions established under the Act, the Department should impose a penalty as provided in G.L. c. 164, § 1E (c).[87]

IX. CONCLUSION

WHEREFORE, for all of the foregoing reasons, the Attorney General requests that the Department reject the Company's proposed rate increase and PBR plan.

Respectfully submitted,

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[87] The Electric Restructuring Act of 1997 ("Act") (Stat. 1997, chapter 164) inserted G.L. c. 164, § 1E(c), which provides that "each distribution, transmission, and gas company shall file a report with the department by March first of each year comparing its performance during the previous calendar year to the department's service quality standards and any applicable national standards as may be adopted by the department. The department shall be authorized to levy a penalty against any distribution, transmission, or gas company which fails to meet the service quality standards in an amount up to and including the equivalent of 2 per cent of such company's transmission and distribution service revenues for the previous calendar year."